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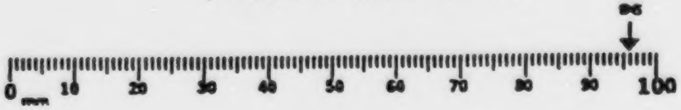

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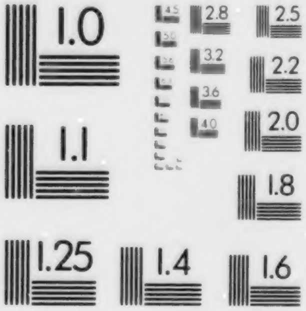

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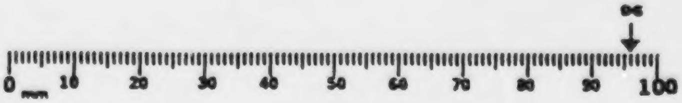

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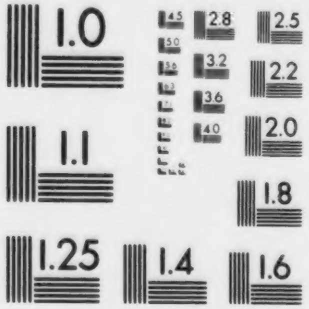

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Electricity Industry Issues Table

Options Paper

November 3, 1999

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Section 1 Table Mandate and Process

Canada's National Post-Kyoto Climate Change Implementation Process was set up, on the direction of First Ministers, to advance Canada's response to the climate change issue and the Kyoto Protocol. The goal of the Process was to engage governments and stakeholders to assess the socio-economic implications of actions to implement the Kyoto Protocol, to prepare for continuing international negotiations to implement the Protocol, to develop immediate actions that could be taken to reduce emissions, and to determine longer term actions that could provide sustained reductions in emissions in order to develop a phased, step-by-step national implementation strategy. (Canada's National Post Kyoto Climate Change Implementation Process, April 9, 1998)

Sixteen Issue Tables were established in order to achieve the above deliverables. The Electricity Table examined mainly electricity generation but also touched on the transmission and distribution elements of the electricity industry to assess the potential contribution that could be made by the electricity and cogeneration industries, including renewable energy, towards GHG reductions. The 28-member Table consists of two independent co-chairs, 5 government officials (l federal, 4 provincial), 8 utility representatives, 4 independent power members (representing renewables, independent power producers, and gas marketers), 3 members from the environmental community, 2 equipment manufacturers plus 1 member each from a coal producer, a distribution utility, an electrical association and an academic. A complete list of Table participants can be found in Annex D

The Electricity Table undertook its work in three phases. Phase 1 established the Terms of Reference, developed a Foundation Paper and planned the Table's analysis work. Phase 2 involved data gathering and cost curve analysis, working with a modeller and expert consultants. For Phase 3, Table members examined the results of the analytical work and developed measures that could either result in emission reductions leading up to the Kyoto Period and/or contribute to Canada's emission reduction target during the Kyoto Period and beyond. This Options Paper is the result of those deliberations.

The Table membership represented diverse perspectives and consensus could not be reached on all measures. However, with certain caveats, the Table is able to support many of the measures. This Report attempts to accurately reflect the views of the Table.

Section 2 Key Messages & Summary

Introduction

Introducing greenhouse gas emission constraints globally and in Canada presents both cost challenges as well as opportunities for Canada's electricity generation sector. The cost challenges lie in the need to turn from least-cost to higher-cost technologies to reduce emissions. Higher electricity prices could either be a problem or an opportunity for Canada's electricity trade with the U.S., depending on how American climate change policy develops. As well, there may be an opportunity for a higher volume of electricity exports to the U.S. Since the potential financial gains are associated with low and non-emitting sources, such as hydro, nuclear, and emerging, non-GHG emitting sources of power, and the costs with coal, there will also be a challenge to devise mechanisms to allocate the costs and benefits in a manner that is seen to be, and is, fair.

Climate change policy is only one of many changes and uncertainties facing Canada's electricity sector. The sector is in the midst of a radical change in structure, with many jurisdictions across North America introducing competition in generation. The industry also faces changing environmental standards and regulatory review processes. With the existing capacity having a long average remaining economic life, and some types of new generation facing long lead times for approval and construction, it is important that climate change policy be developed in light of the current and future situation of the industry, provide adequate lead time for generation decisions and be integrated with other policy measures that will affect the industry.

The Electricity Table undertook a detailed and systematic analysis of the minimum cost changes in the mix of generation required to reduce emissions from generation. This led the Table to focus its effort on two areas in its consideration of measures:

- ***Preparatory Measures*** -- those that could be enacted in the next 1 to 2 years. The bulk of the Table's attention was devoted to formulating measures that would contribute to the availability of least-cost, low-emission technologies for deployment in a commitment period. The Table developed one or more measures for each of the major types of generation.
- ***Commitment Period Measures***--Emission pricing was identified by the Table as the most efficient least-cost method for the industry to meet a given constraint. The Table did not address the allocation issue, which is fundamental to emission pricing.

In its quantitative analysis, the Table confined itself to the electricity supply sector and focussed on the cost of changing the mix of generation to reduce emissions. It did not look at the overall impact on the electricity sector of implementation of the Kyoto Protocol, viewing this as the mandate of the Analysis and Modelling Group in its work on the "roll-up". Nor did it consider the effect on other sectors of the economy of imposing costs on electricity generation to reduce emissions, or the effects on conservation, electricity demand or supply measures considered by other sectors nor did it deal with the effect of climate change on potential sources of electricity generation. Many of these are being examined by other Tables, and these too will need to be addressed in the roll-up analysis.

Given its mandate, the Table largely confined itself to analyses based on the NRCan 2020 forecast. However, due to concerns expressed by Table members, some limited analysis was at higher demand electricity and natural gas price levels.

No measure is intended to decrease environmental standards, nor bypass due legal process or meaningful public consultations

The remainder of this section outlines the Table's key messages about its current situation, the challenges and opportunities that the sector would face in a carbon constrained world, some high level policy issues, and a number of concerns of those who would be most affected by GHG emission constraints. Additional information, and an overview of the Table's technical analysis, is provided in the Annexes.

Key Messages

Climate change policy measures for the electricity sector need to be viewed in the context of the current situation of the electricity sector.

Existing generation capacity in Canada is as follows:

- Total capacity of about 112,600 MW, of which
  - Fossil fuel generation capacity is about 31,000 MW (*i.e.*, 28% of total capacity). Of this, 18,000 MW is coal-fired generation.
  - Remaining useful lifetimes of fossil fuel plants range from less than five years to more than 35 years.

Uncertainty about electricity demand growth arises from a combination of uncertain economic growth and the evolving relationship between electricity demand and economic activity. Demand uncertainty makes the cost of achieving any particular level of aggregate emissions uncertain, since the growth rate of demand affects the total capacity required and is thus a major factor in determining the emission reduction challenge. This uncertainty exists in most economic sectors, but is more significant in the electricity industry because of the long lead-time necessary for construction of some types of new capacity. The structure of the electricity supply business has changed considerably compared to the period when utilities planned and added existing capacity. These changes include:

- Changes in technology and options available, such as:
  - Advances in natural gas generation technology: turbines, fuel cells, micro turbines
  - Advances in wind power technology.
  - Anticipated advances in combustion technology
- *De facto* moratorium on new nuclear capacity.
- Significant restrictions on new, large hydro projects.
- Changes in fossil fuel pricing – competitive and volatile natural gas prices.
- Deregulation of electricity generation in Alberta and Ontario and in the U.S. Potential for deregulation in other Canadian jurisdictions, resulting in competition at the wholesale level in some jurisdictions, and at the retail level in others. This will lead to expectations by consumers of falling electricity prices and having choice in deciding on generation supply. Choice of new generation will be based on this competitive market.
- Closer wholesale market links with adjacent U.S. markets will arise. Competition between provinces and the U.S. will become an increasingly important factor.
- Links between the North American natural gas market and the competitive wholesale power market will continue to grow.
- Change in players:

- Significant industrial end user co-generation and other forms of distributed power to meet own needs and supply others through the market.
- Global players will enter if/when the regulatory environment is clear(er).

These factors will result in falling market shares of many established players

Environmental standards are also changing, with stricter limits on SO_2, NO_x, particulate matter (PM), and mercury emissions. Cumulative effects, waste heat, and effects on fish migration are of increased concern as is the transborder nature of many pollution issues (especially in the East). Nuclear power continues to be controversial. As a result:

- There is an expectation of rising standards requiring significant investment in emission control devices on existing coal and oil plants, or in repowering plants with natural gas;
- Large hydro projects are subject to increased scrutiny of environmental and social effects.
- Existing nuclear plants are subject to a mix of increasingly detailed regulatory requirements.

Finally, there is overall uncertainty about global and Canadian climate change policy.

The electricity generation challenge is to make efficient generation investment decisions to meet demand growth and replace worn out capacity, in the face of considerable underlying uncertainty about technology, fuel costs, demand and global policy. The capital intensive, long-lived generation capacity makes it very costly to respond to new standards after plants have been built or to change direction quickly with respect to the overall mix of types of generation. It is therefore socially desirable to be clear about both local environmental and greenhouse gas objectives/policies affecting existing and future generation. This is necessary both to provide guidance to generation companies to make efficient decisions and to be fair to those consumers and investors who must bear the cost of the changes. With a competitive generation sector, a reasonable degree of policy certainty is necessary to avoid restricting investment or inflating the cost of power. The integration of decisions on other pollutant issues with climate change is critical.

Climate change policy challenges and opportunities facing the electricity sector

Introducing GHG emission constraints globally and in Canada presents both cost challenges and profit opportunities for Canada's electricity generation sector.

The cost challenge lies in the need to turn from least-cost to higher cost technologies to reduce emissions. Higher electricity prices could either be a problem or an opportunity for Canada's electricity trade with the U.S., depending on how American climate change policy develops. Since the potential financial gains are associated with low and non-emitting sources, such as hydro, nuclear, and emerging, non-GHG emitting sources of power, and the costs with coal, there will also be a challenge to devise mechanisms to allocate the costs and benefits in a manner that is seen to be, and is, fair.

Challenges for electricity sector in meeting large reductions in GHG emissions.

There are two types of costs involved in moving to lower emission generation over the medium and long term:

- Choosing higher cost, lower emission generation using existing technologies.
- Investing in research, development and demonstration (RD&D) to develop lower cost, low or non-emitting technologies that could be adopted in the future.

Reducing emissions earlier results in higher cost per tonne of CO_2 reduced if existing, higher emitting capacity must be abandoned prior to the end of its economic life or if RD&D will make lower cost non-emitting technologies available in the future. On the other hand, the addition of new capacity to meet growing load requirements or to replace existing capacity at the end of its life represents a unique opportunity to choose low or non-emitting generation.

Large existing investment in coal mines and generating capacity represents a huge sunk cost in the existing infrastructure. Premature retirement of coal plants and replacement by low emitting capacity would involve significant investment in new capacity earlier than would otherwise be required. This will place an associated burden on customers, taxpayers or shareholders arising from covering the incremental cost of replacing existing generation, *i.e.* paying for the power from the new generation plus the remaining stranded capital value of the prematurely retired coal capacity.

Hydro development faces a number of uncertainties that could limit its availability to reduce GHG emissions: regulatory, public acceptance, First Nations relationship issues and market risks of long lead times, long life, capital intensity, and need for additional transmission capacity.

Even under "policy as usual" (*i.e.,* the NRCan base case without a carbon constraint), a major part of new supply is assumed to be low-emitting hydro. Failure of planned new hydro to be built would cause a significant increase in GHG emissions.

Wind power is currently more costly than the major generation technologies. It also has high initial investment costs per unit of effective capacity. Expertise and capability to develop capacity in wind and other non-emitting, emerging technologies are not currently available in Canada to supply the volumes contemplated under some GHG emission reduction scenarios. The potential for reducing costs is tied to economies of scale in development, financing and manufacturing, which require a growing market share for these technologies.

Nuclear power, while a significant non-GHG-emitting technology that has high initial investment costs per unit of effective capacity, bears the burden of ongoing public acceptability issues. The future use of a few units of existing Ontario nuclear capacity is uncertain (Bruce A, in particular). This represents a significant amount of non-GHG-emitting capacity.

Coal-fired generation could be one of the lowest-cost technologies available in some regions of Canada over the long term if there is no constraint on carbon. However, for coal to be an option in the commitment period, the costs of CO_2 capture and geological storage or new clean coal technology would have to decrease from their currently projected levels, or natural gas prices would have to increase.

CO_2 capture technology requires cost reductions and demonstration to play a significant role in the commitment period.

Finally, there are long lead times for major generation/transmission increments, and a need to match generation plans with enhanced yet environmentally and socially acceptable transmission access.

Specific opportunities for electricity industry

Existing hydro and nuclear generation capacity stand to gain from the higher value that non-emitting generation will have in a GHG emission constrained world. The ability of the sector to provide additional development of efficient, low cost, low emission generation options creates the possibility of higher returns to new, non-emitting generation in a world of GHG constraints.

New, low-emission generation could support a higher electricity share of both primary and secondary energy supplies in Canada, and increased CO_2 exports to the U.S.

The successful development of low cost capture technology would have an important potential for application not only in Canada, but also in other countries that are likely to remain heavily reliant on coal, *e.g.* China, India.

Actions to reduce GHG emissions can jointly address other emissions as well.

High-level policy issues identified by the Table

Canadian policy makers face a policy dilemma:

- Climate change is a long-term global issue requiring major changes in technology or consumption patterns to address, both of which take considerable time to take effect. Hence, it is urgent for the world to begin, even at a risk management level of actions, to address climate change. These involve investment choices among alternative technologies that affect emission intensity of activity for many years for capital goods with long service lives (e.g. 40 years for a coal-fired power plant). Thus, minimising costs in the face of future GHG emission constraints requires current actions that anticipate those future constraints.
- However, the appropriate degree of constraint and therefore, the level of effort to reduce emissions for Canada, are inherently uncertain.

While the scientific evidence warrants global action, even if only on the grounds of prudent risk management, the timing and degree of global effort that will be undertaken is unclear, given the range of views about what should be done and the uncertain ability of the international community to jointly commit to action.

While Canada has one of the higher levels of emissions per capita, we contribute, as a nation, only 2 percent to total global emissions. Canadian action thus makes economic sense only as part of a global effort to reduce emissions.

Canadian policy makers thus face both the uncertainty of international action and the urgent need to prepare the ground to begin reducing emissions and to establish clear signals on policy to achieve reductions.

Canadian response to the issue is inherently a matter of managing policy risk in the face of uncertainty about global action. There is therefore an urgency to begin on a course that can respond with increasing effort as international commitments to global policy materialise.

In the absence of agreement on the appropriate response to this policy dilemma, agreement on the timing, nature and extent of measures is difficult. There is a range of views among members of the Table on the appropriate degree of near term action. For some members, the reductions in emissions required under the Kyoto Protocol represent only an initial step in the much larger reductions that will be required over the long term. They see it as important to begin immediately to adopt measures that will enable Canada to meet its Kyoto target.

For some other members, an early start should be tied to phased reduction in emissions that begins earlier but reaches the Kyoto Protocol target at a later date or ties the decision on future escalation of effort to actions by Canada's trade partners and competitors. In their view, the relatively large step represented by Kyoto targets makes governments reluctant to ratify the Protocol and makes an early international decision on climate change policy uncertain. In addition, in their view, an early international decision on a policy that is more likely to be achieved would make action to reduce emissions both more certain and less costly.

With global policy uncertainty an inherent risk beyond Canada's control, the design of Canadian policy should respond to that risk in the context of actions by other countries as well as other risks and changes facing the Canadian economy and society.

With an electricity sector that is significantly more fossil-intensive[1], the U.S. may well develop a sectoral approach to emission reductions different from Canada. That could have significant trade implications with both risks and opportunities. Given the significant Canada-U.S. trade in electricity and other energy it is important for Canada and the U.S. to adopt a co-operative approach and compatible climate change policies.

Concerns of companies with significant fossil fuel capacity

Companies with significant fossil fuel capacity are concerned that coal-fired generation could be targeted for a disproportionate share of reductions on the basis of the simple idea that because coal is the most carbon intensive fuel, the lowest cost reductions will necessarily come from reducing coal use, without a thorough economic analysis of the lowest cost emissions economy-wide and internationally. There is also concern that measures reducing coal use by 2010 will prove to be shortsighted and costly in the long run, as the world will continue to require fossil fuels. Finally, these producers are concerned that the government may interfere in the competitive market through specific interventions such as subsidising transmission or providing loan guarantees or other subsidies to specific generation projects rather than relying on general policy tools.

Concerns of environmentalists

All measures identified in this paper must meet the tests of environmental and social acceptability and sustainability, including due legal process, meaningful public consultation, and consistent and rigorous enforcement of environmental laws. The development of any form of power generation should meet these tests.

Representatives of environmental groups at the Table believe that the use of nuclear power as a response to climate change poses an unacceptable risk to human health and safety and the long-term risk of radioactive contamination of ecological systems. Consequently, they recommend that government not pursue that option

Some environmentalists on the table believe that most large hydroelectric developments have significant environmental and/or social impacts that make them unacceptable. They therefore do not see large hydro as a significant part of the solution to climate change. Other environmentalists see greater use of hydroelectric power as a way to address climate change commitments.

Summary of Measures

The set of measures proposed by the Electricity Table are designed in light of policy makers' need to face the global uncertainty about climate change policy while addressing the urgency of preparing the ground to begin reducing emissions and sending clear signals on policy to achieve reductions.

The measures identified by the Table to achieve significant reductions are separated into the following categories:

- A set of Preparatory Measures designed to increase the likelihood that low- or non-emitting generation options will be available at relatively low cost for deployment in the commitment period.
- Measures toward a commitment period target:

---

[1] *There is a large difference in the fossil fuel shares in electricity: U.S. 60% coal versus < 20% in Canada, 54% of U.S. emissions from electricity generation versus 17% in Canada*

- a measure for significant reductions prior to the commitment period designed to effect early reductions in emissions, as part of an early phased approach to reductions; and,
- Commitment period measures designed to achieve reductions in line with an international commitment.

The Table considered a number of other measures, which received only limited support. These are included in the report but are not summarised here.

Preparatory Measures

All measures identified in this paper must meet the test of environmental and social acceptability and sustainability, including due legal process, meaningful public consultation, and consistent and rigorous enforcement of environmental laws These measures are needed to put building blocks in place to contribute to the availability of, and market support for, lowest cost, low-emission technologies to achieve large reductions in the future

- Emission reporting and consumer information.
- Policy clarity and regulatory efficiency to contribute to the availability of environmentally and socially acceptable hydro developments.
- Transitional financial support for emerging non-GHG technologies tied to a sound business case demonstrating the ability of these technologies to compete without support during a period of GHG constraints.
- Policy clarity for nuclear power to determine whether it is to be an option and, if it is an option, regulatory efficiency to remove unnecessary costs and reduce uncertainty for existing projects and to contribute to the availability of environmentally and socially acceptable new projects.
- RD&D support for high efficiency, low emission fossil fuel technology, especially CO_2 capture and geological storage.
- Removal of barriers to expanded inter-provincial transmission capacity.

Measures toward a Commitment Period Target

The Table recognised the importance of *credit for early action* and the measures to provide such credit, which are being developed elsewhere. Those measures should be designed to achieve significant near term reductions as a step in a transitional, phased approach of moving from "business as usual" to more costly measures under a commitment period in accordance with an international commitment. This credit would also assist industry in managing the risks of the impacts of future global climate change policy. Credits for early action must be based on verifiable reductions, transparency of data, and the need to achieve real reductions before credits are made available.

Commitment Period Measures

Emission pricing can result in the most efficient, decentralised decisions on how to reduce emissions. For a given national emission target or level of reduction as part of a global effort in line with the U.S. and our major trade partners and competitors, pricing would be preferred in principle over less flexible approaches to mandating reductions. However, as with any policies aiming to reduce emissions, three important aspects of policy must be addressed.

- The impact on the competitiveness of Canadian industry,
- An appropriate and fair resolution of the allocation issue, and

- Effective and efficient access to choosing lower cost actions to reduce emissions in the rest of the world over higher cost actions in Canada as a means of achieving part of Canada's required total emission reductions. Some Table members, however, are of the view that a majority of reductions should occur domestically.

The Table examined commitment period measures in the context of a given national emission target or level of reduction as part of a global effort in line with our major trading partners and competitors.

Emission Pricing

Subject to the three policy aspects noted above being addressed appropriately, emission pricing would be preferred in principle over less flexible approaches to mandating reductions. Because it relies on decentralised decisions on where and how to make reductions, the Table found that emission pricing is the most efficient approach to achieving an emission reduction target.

Emission pricing could be implemented either as an emission trading system, or as a greenhouse gas (GHG) tax. Both of these forms of emission pricing can encompass variations in design detail, in part linked to resolution of the critical allocation issue.

Many of the Table members consider it important to point out that identifying an efficient policy tool to meet a given goal is different from agreeing that the policy goal itself is appropriate. Some Table members want to note their concern that this report, by identifying the most efficient and effective policies to achieve the Kyoto level of reductions, will be misinterpreted as support for implementing the Kyoto target, about which they have strong reservations.

Large Scale Binding Portfolio Standard

Large scale, binding portfolio standards or quotas, which require regulatory specification of the minimum percentage or amount of generation comprised of non-emitting technologies is another means of meeting commitment period targets. In principle, regulators could use the best available information to determine an efficient mix of generation required to achieve some target level of GHG emissions and impose that mix through regulation. However, most members of the Table view portfolio standards and quotas as a command-and-control approach that would turn out to be a more costly and a less efficient way of achieving emissions reductions than an appropriately designed emission pricing system. Some environmentalists on the Table were, however, of the view that, with careful design, such a measure would be appropriate in addition to emissions pricing.

Table members want to emphasize the importance of examining climate change policy in the context of the current and future situation of the industry and formulating climate change and other policy measures in an integrated manner.

Analysis of Emission Reduction Costs using the MARKAL Model

Analytical Approach

The Electricity Table spent a considerable amount of its time working with HALOA Inc to frame the analysis that underlies the measures described in this Report, using the MARKAL economic model. The analysis done for the Table using the electricity sector sub-set of the MARKAL model (referred to as E-MARKAL) was exclusively focussed on electricity generation in Canada and did not take into account changes in international electricity trade, other sectors or economic interactions generally. It did not consider the effects of meeting GHG emission constraints on the international competitiveness of Canada's generation sector, or on electricity demand in domestic and export markets. These can only be assessed in the roll-up analysis of the overall impact of the constraints on Canada. This Table's analysis addressed the issue of achieving the least-cost means of changing the mix of generation to achieve a specified level of emissions from 2008 to 2030, under differing assumptions about a number of major factors that determine that cost, including:

- level of demand
- natural gas prices
- availability of Ontario Power Generation's Bruce A nuclear plant
- availability of new hydro
- future cost of CO_2 capture and geological storage.

The E-MARKAL model solves for the minimum cost mix of generation across Canada required to meet a projected pattern of demand including a fixed volume of exports, given the availability and costs of existing and new generation capacity, natural gas prices and the discount rate used. The model gives the optimum planning solution assuming perfect foresight and the equivalent of a perfectly functioning market. Under these conditions, the model estimates that emissions could be reduced by changing the mix of future generation at costs that are lower than the power companies expect could be realised in the actual world of uncertainty and imperfect decisions. This result gave rise to concerns that the analytical work could be taken out of context and drive an unbalanced focus on electricity sector reductions simply because the Table undertook more rigorous analysis than has been done for other sectors.

There are a number of factors that limit the industry's ability to bring on new capacity in the amount, the time frame and cost estimated in the Table's analysis. The model assumes that the only barriers to operating existing capacity or building new generation and transmission capacity are economic costs and resource availability. The regulatory and policy barriers that a number of the preparatory measures aim to address are not taken into account in the model analysis. (Alternatively, the regulatory and policy barriers that these preparatory measures address must be resolved if the change in the generation mix projected by the model is to be achieved).

Summary of Analytical Results of GHG Emission Constraints

To assess the costs of changing the mix of generation to reduce emissions, the unconstrained, minimum cost mix of generation for the period 2000 to 2030 was compared with the cost of the mix with various levels of constraints. The difference in cost represents the costs of meeting the constraints.

The pattern of results reflects the need to shift from least cost to higher cost, lower emitting generation to meet lower emission targets. Annex B to this report provides considerable background information on the modelling approach used, as well as quantitative detail on the nature and costs of changes in the mix of generation required to meet emission targets under various assumptions.

For the Table's base case (tuned to be closely aligned with NRCan's 2020 Outlook) with total generation of 644 TWh, reducing emissions from the no-constraint level of 118 Mt of CO_2 to the constraint level of 90 Mt (94% of 1990 levels) in 2010, requires a change in the mix of generation as follows[2]:

- natural gas generation increases by 22 TWh, with a shift within gas from steam and simple cycle gas turbines to combined cycle and cogeneration plants
- hydro increases by 9 TWh
- biomass increases by 4 TWh.

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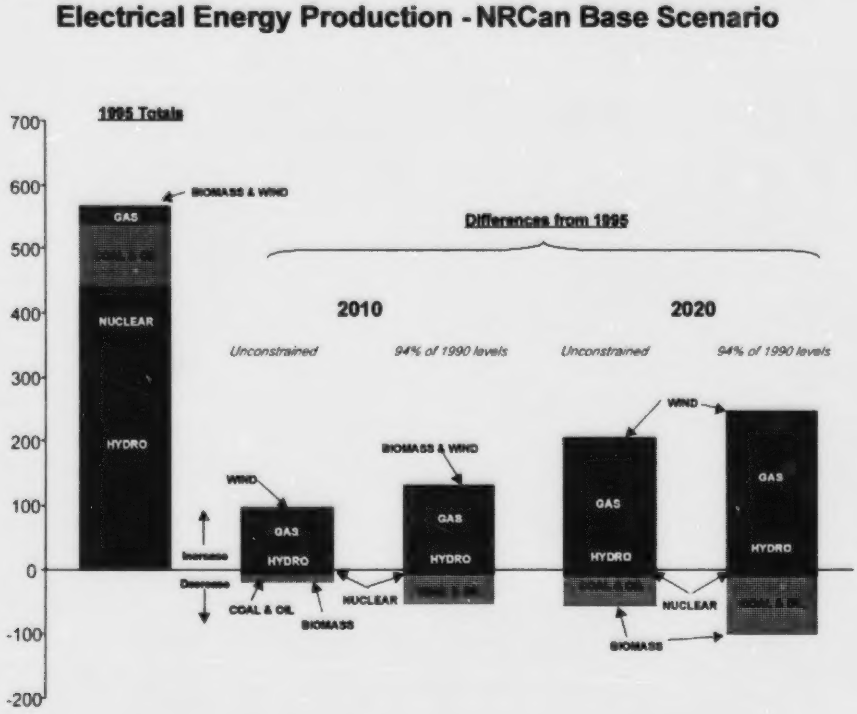
[2] *Does not include 3.7 TWh representing interprovincial trade*

- coal decreases by 39 TWh
- oil decreases by –0.3 TWh.
- no change to wind and nuclear power generation.

These changes are illustrated in the Figure 1, which shows the mix of generation in 1995 and changes in each type of generation from the 1995 level in 2010 and 2020 under no emission constraint and a constraint of 94% of 1990 emissions.

In many Table members' view, both natural gas prices and electricity demand will be much higher than in the NRCan base case. The Table tentatively examined one combination of these factors (intermediate demand and intermediate gas prices), and found a dramatic increase in the cost of meeting the constraint – roughly double the marginal cost of meeting the constraint under base case assumptions. At a higher demand level, considered as the aggregate of utility expectations, and without changing any other variables from the NRCan base case, such as gas pricing, the resultant marginal cost increase would be 2.5 times the base case

Figure 1



The Table examined several scenarios in which the unconstrained starting points differed from the base case. For these scenarios, the required changes in the mix of generation varies from that required in the base case as follows:

- If no new, large hydro is allowed, the unconstrained emissions in 2010 would be 5 Mt higher than the base case and, the reliance on natural gas and the reduction of coal are even greater.

+8

- If the Bruce A nuclear plant does not return to service, the unconstrained emissions would be 6Mt higher than the base case in 2010. To meet the constraint, the increase in hydro and gas, and the required decrease in coal are greater.
- In a higher gas price case, *i.e.*, in 2010, $6.00/GJ versus $1.96 in Natural Resources Canada's business as usual base case (in constant 1990 dollars), there is more coal in the unconstrained situation, and therefore unconstrained emissions are 36Mt higher. Compared to the base case, the reduction in coal from 1995 levels to meet the constraint is smaller because the constraint is met less by gas and more by hydro and wind.
- In the high demand case, with a total generation of 722 TWh and unconstrained emissions that are 38Mt higher than the base case in 2010, the unconstrained case has more hydro, coal and gas. Meeting the constraint requires larger increases in natural gas, hydro, wind and biomass, and larger decreases in coal.
- If CO_2 capture and storage become available in sufficient volume, at low enough cost, then a much smaller reduction in coal is required to meet the constraint.

These changes in the mix of generation have implications for net revenues flowing to existing generation plants in the emission reduction scenarios compared to revenues over the remainder of their economic lives in the no-reduction case. Those types of generation facing decreases due to the constraint (coal, oil, and gas steam) would receive lower revenues to cover their sunk investment costs. Mechanisms that could be used to cover the stranded costs of such generation are not identified.

The Table was able to analyze some of the preparatory measures using E-MARKAL. The results are reported in the detailed description of the model results in Annex B.

Most people recognise that emission pricing is the most efficient policy means of achieving significant reductions. The Table's analytical work was very effective in illustrating the higher cost of approaches that impose a generation mix that differs significantly from the cost minimising mix that results from the market approach of emission pricing.

This supported the philosophical preference of many Table members for flexibility in the methods of reducing emissions, which led the Table to identify emission pricing as the main commitment period measure, subject to dealing fairly with the stranded cost and allocation issues, and ensuring access to low cost reductions in other countries.

Links to Other Sectors

The measures adopted to achieve significant emission reductions in the electricity generation sector will raise generation costs and, in all likelihood, raise electricity prices. This would be the case in both a competitive power market and a monopoly utility environment. While some of the cost impact could fall on generators in a competitive market, some of it will fall on electricity consumers. The impact on those consumers has not been analysed by this Table. It is left to the integrative roll-up analysis.

The measures proposed by other sector Tables could well affect the demand for electricity or the supply costs of some generation options. These also will need to be integrated with the electricity generation sector analysis at the roll-up stage.

Section 3 Measures Overview

The measures identified by the Table are comprised of two subsets:

1. Preparatory Measures: a set of measures designed to increase the likelihood that low or non-emitting generation options will be available at relatively low cost for deployment in the commitment period.
2. Commitment Period Measures:
    a) Measures for significant reductions prior to a commitment period: a significant incentive in the form of a transferable government credit for early actions to reduce emissions beginning in the near future and leading up to the commitment period.
    b) Measures to be introduced during the period when emissions must be reduced in accordance with an international commitment under global climate change policy: emission pricing and binding portfolio standards.

The Preparatory Measures are considered necessary to position the electricity generation sector to be able to achieve at the lowest cost whatever levels of emission reductions are pursued in the future. While some of these measures (e.g. financial support for emerging, non-emitting technologies) would contribute to pre-commitment period emission reductions, their prime justification and focus are positioning the sector for the future These measures are summarized in the following tables and described in greater detail in Section 4

All measures identified in this paper must meet the test of environmental and social acceptability and sustainability, including due legal process, meaningful public consultation, and consistent and rigorous enforcement of environmental laws

PREPARATORY MEASURES (2000-2003)

Name of Measure	**Nature of Measure/ Impacts**	**Costs to Implement**	**Level of Table Member Support (Subject to Caveats)**	**Caveats on Some Table Members' Support**	**Comments**
1. Emission Reporting *Phased approach to implementing a comprehensive emission reporting system.*	Preparatory. Essential building block for other core and Kyoto target measures.	No estimate. Most data already exists, but is not well reported.	Strong Support	Appropriate safeguards for confidentiality.	Timing, form should be based on international and domestic policy decisions. Phased approach leading to uniform and broadly applied rules across sectors and jurisdictions. Need for consistent accounting methodologies across sectors and jurisdictions.
2. Consumer Information *Disclosure of the generation mix/ environmental attributes to electricity consumers*	Preparatory. Complimentary to other core measures (necessary for measure 7D)	$50,000 – 100,000 per utility, based on limited U.S. experience.	Strong support	Reservations about how much information customers want to see.	Could be voluntary in provinces with retail monopolies and mandatory in others. Importance of harmonized disclosure rules increases with inter-provincial or international electricity trade. Should be put on retail bills and/or promotional material.

PREPARATORY MEASURES (2000-2003)					
Name of Measure	**Nature of Measure/ Impacts**	**Costs to Implement**	**Level of Table Member Support (Subject to Caveats)**	**Caveats on Some Table Members' Support**	**Comments**
3. Regulatory Efficiency Improvements					
3A) Improve regulatory efficiency, Major Projects *Reduce regulatory uncertainty for power plants that will meet Canada's environmental, social and economic policy objectives by ensuring that environmental review and other approval processes are as open, clear, fair, timely and efficient as possible, while ensuring effective environmental protection.*	Preparatory. Potentially large reductions. Increase number of low-GHG emitting projects built.		General support	Any changes in the review process should not lead to inadequate environmental protection or the bypassing of due legal process and meaningful public consultations. Consistent and rigorous enforcement of environmental laws is essential.	Intended effect is to remove delays, uncertainty and disproportionate risk. Expect cost savings to power companies. Would contribute to sustainable development. Considered necessary to position the electricity sector to achieve emission reductions at lowest cost.
3B) Incorporate greenhouse gas considerations explicitly in the review and approval processes	Preparatory. Consideration of GHGs, as well as local impacts, when evaluating projects could result in more low/non-GHG emitting projects being developed.		Mixed support.	Any changes in the review process should not lead to inadequate environmental protection. Not proposing a detailed GHG analysis, just a general recognition of the impact of the project on global GHG emissions	In the absence of national GHG regulation, there will be increased pressure on provincial regulators to take GHGs into account. May increase complexity and uncertainty of regulatory process for projects with GHG emissions.

PREPARATORY MEASURES (2000-2003)					
Name of Measure	**Nature of Measure/ Impacts**	**Costs to Implement**	**Level of Table Member Support (Subject to Caveats)**	**Caveats on Some Table Members' Support**	**Comments**
3C) Address barriers to inter-provincial transmission construction to allow low/non-GHG emitting technology to be optimized between provinces.	Preparatory. Low or non-GHG emitting supply may displace more emitting supply in other provinces depending on cost.	Unspecified amount of government support needed.	General support	Suggested incentives could interfere with competitive market under further restructuring of the electricity industry in Canada. Projects must be environmentally and socially acceptable and based on meaningful public consultations. Support for this measure depends on how it is financed	Cost of complying with emissions reductions increases when transmission is constrained.
4. Plan for Fossil Fuels					
4A) Financial support for research, development and demonstration: capture and geologic storage of CO2	Preparatory. Potential to reduce emissions from fossil fuel plants. Potentially for very large reductions.	Unspecified amount of government support.	Strong support	Caution about optimistic assumptions (technological and geological), reliance on unproven technology. R&D support for non-fossil options should also be forthcoming. Projects must be environmentally and socially acceptable.	Could have a large effect on the cost of emission reduction in Alberta and Saskatchewan. Significant opportunity to export technology via CDM projects in developing world.

PREPARATORY MEASURES (2000-2003)

Name of Measure	Nature of Measure/ Impacts	Costs to Implement	Level of Table Member Support (Subject to Caveats)	Caveats on Some Table Members' Support	Comments
4B) Financial support for research, development and demonstration: fossil fuel technologies with potential to significantly reduce GHG emissions.	Preparatory. Potential to reduce emissions from fossil fuel plants through increasing combustion and fuel efficiencies.	Unspecified amount of government support.	General Support	Should not duplicate R&D that is already being done internationally. Should be done with the overall concept of cost effectiveness in mind. Should consider environmental and social impacts when deciding on R&D for particular technologies.	May help mitigate regional sensitivities and dependencies on fossil fuels. There are some important fossil fuel niches for Canada such as R&D on oil sands extraction.

PREPARATORY MEASURES (2000-2003)

Name of Measure	Nature of Measure/ Impacts	Costs to Implement	Level of Table Member Support (Subject to Caveats)	Caveats on Some Table Members' Support	Comments
5. Plan for Hydro					
Address barriers to Hydropower A) *Federal and provincial governments to encourage development of the appropriate scientific criteria for the use of hydro resources in Canada and elsewhere (e.g. development agencies, Clean Development Mechanism,* Commission for Environmental Cooperation). B) *Federal and provincial governments to acknowledge hydro as a renewable and a low GHG emitting source of electricity.* C) *Federal and provincial governments would address other obstacles to environmentally and socially acceptable hydro in forming an ongoing part of the electricity sector's response to climate change (e.g. improvement in the relationships between developers of new hydro and directly affected communities, especially aboriginal communities, and further research into fish impacts and their mitigation.*	Preparatory. Potentially very large reductions, increase number of hydro projects built.		Strong support.	Need to ensure through public processes that any hydropower developments are environmentally and socially acceptable. Any review of regulatory requirements should not lead to inadequate environmental protection (see 3A)	Government needs to address regulatory issues and public concerns. Measure needs to be initiated now considering the long lead-time of hydro developments (up to 10 yrs.). Model estimates the cost of compliance will be over two billion additional dollars over 30 years net present value, to meet 6% below 1990 constraint, if no new large hydro is permitted. The Table acknowledges that there is scientific/technical basis for recognizing hydro as renewable. It also recognizes that environmental and social acceptability of hydroelectric developments is specific to the site and the design of the project. The Table is using the term 'renewable' to refer to the replenishment of supply by natural cycles. The Table recognizes that 'renewable' is not synonymous with the broader concepts of green power and sustainability, which it did not address. Some Table members caution that there is a need to examine the impact of climate change on hydro capacity in the future. Other members believe that any impact could be positive as well as negative

PREPARATORY MEASURES (2000-2003)

Name of Measure	Nature of Measure/ Impacts	Costs to Implement	Level of Table Member Support (Subject to Caveats)	Caveats on Some Table Members' Support	Comments
6. Plan for Nuclear					
Clarify Nuclear Policy and Resolve Nuclear Regulatory Issues as Required *A) Governments to clarify whether there is a place for nuclear power in Canada's future electricity supply industry, in particular, with regards to climate change.* *B) If so, then there is a need for governments to resolve regulatory issues regarding nuclear power in forming an ongoing part of the electricity sector's response to climate change.*	Preparatory. Large reductions from other sources necessary in first budget period if existing nuclear plants are not available. Could maintain/ extend life of existing reactors, reduce lead times for new projects.		Strong support for clarification of nuclear power's role. Table divided on the merits of nuclear power.	Safety, long term storage of wastes and other issues need to be addressed. Any changes in the review process should not lead to inadequate environmental protection. Policy changes affecting the nuclear industry should be taken after meaningful public consultation.	Need clear signal on nuclear issue from governments for public and private investors. Opportunities exist to shorten the lead-time through public awareness and streamlining the regulatory process. Some see nuclear as a substantial part of the solution to climate change mitigation. Loss of this option is expected to raise compliance costs under certain conditions. Unnecessary regulatory risk in current approach for existing plants Successful nuclear in Canada would result in substantial export opportunities. Some Table members do not support nuclear power as a solution to climate change.

PREPARATORY MEASURES (2000-2003)					
Name of Measure	**Nature of Measure/ Impacts**	**Costs to Implement**	**Level of Table Member Support (Subject to Caveats)**	**Caveats on Some Table Members' Support**	**Comments**
7. Plan for Emerging, Non-GHG-emitting Technologies					
Financial Support for Emerging non-GHG emitting Technologies (Overall plan comprising measures 7A-7F below in some combination)	Preparatory. By 2010, supported capacity leads to reduction of 2-3 Mt/year. Intent of this measure is to financially support promising climate-friendly technologies in the expectation that their total costs will come down as a result of the market created by the support. This could reduce the eventual cost of compliance with a binding emission constraint.	Estimates from the modelling and Table expertise are on the order of $200-500 million (present value over 30 years).	Strong support for this basket of options, as a preparatory measure at the funding levels examined.	Support is contingent on the degree of confidence that the plan will produce real cost reductions. Program must contain sunset clauses and ramp-down features, be production based rather than investment based, include domestic manufacturing capability development and have defensible baseline technology cost projections.	Emerging, non-GHG emitting technology options become economic in North America as both Canada and the U.S. respond to Kyoto Not all measures would be implemented in every province. Basket of tools. Program must be designed to minimize possibility of free riders. Some Table members caution that there is a need to examine the impact of climate change on energy technology resource capacity in the future. Other members believe that any impact could be positive as well as negative
Name of component of support measure				**Caveats and comments**	
7A) Government procurement of electricity from emerging non-GHG emitting sources.				Amounts currently budgeted are only a fraction of total support required from the whole package of measures.	
7B) Installation on government buildings of site-based generation using emerging non-GHG emitting technologies				Possible outreach benefits resulting from the display of climate-friendly technologies on buildings. Very limited impact – approximately 15kt/year.	
7C) Production credits				Significant potential, depending on the extent of support.	

PREPARATORY MEASURES (2000-2003)

Name of Measure	Nature of Measure/ Impacts	Costs to Implement	Level of Table Member Support (Subject to Caveats)	Caveats on Some Table Members' Support	Comments
7D) Rebate on retail bill premiums paid for climate-friendly electricity from emerging technologies				Splits the cost of developing emerging non/low-GHG technologies between interested consumers and government. An upper cap on total subsidy payments or on number of subscribed consumers may be required to limit government expenditure. Source disclosure and 'environmental content' certification would be required to provide consumer confidence and protect against fraud. Applies most effectively in provinces with retail access, although regulated rate options are also possible. Table was divided on the potential of this measure.	
7E) Generation quota or portfolio standard. (small percentage) Quota requires fixed amount of one or a set of low/ non-GHG emitting technologies. A Generation Portfolio Standard guarantees a minimum percentage.				No estimate of administrative costs. Industry and customers bear all the costs. Some members prefer explicit, direct financial support. Some members view a small standard, tailored to resource base of province, coordinated to share regional burden useful as part of the transition to an emissions pricing mechanism. Some prefer quotas to portfolio standards. Needs to be differently designed for a competitive market and a monopoly. Significant potential, depending on the size of the quota or standard.	
7F) Net metering for non/low-emitting sources, small systems (such as rooftop photovoltaics and micro-cogeneration).				Positive sign for smaller enterprises and homeowners. Encourages site-based generation. Small impact on emissions reductions. Technical issues with small generator interconnections include power quality, service reliability, equipment protection, and metering arrangements. Regulatory and/or utility involvement required.	

PREPARATORY MEASURES (2000-2003)

Name of Measure	Nature of Measure/ Impacts	Costs to Implement	Level of Table Member Support (Subject to Caveats)	Caveats on Some Table Members' Support	Comments
8) RD&D for Longer Term ptions Financial support for research, development and demonstration: non-GHG producing technologies.	Preparatory. Could bring technologies with potential rapid cost reductions into the market.	Unspecified level of government support.	General Support	Depends on size of budget under consideration, where spent. There is a need for balance in use of the available funds.	Science, engineering, testing and refinement needed to bring non-GHG producing technologies to commercial readiness. OERD, PERD are the responsible agencies federally, but provinces and companies have large research facilities as well. Could be possible to use a federal/provincial/industry consortium.
9. Other					
9A) Remove Effect of Tax Induced Barriers to Investment in and Competitiveness of No/ Low GHG Generation	Preparatory. Intended to encourage non-GHG emitting technologies.		Support in principle. No convergence on details.	The corporate tax system may not be the only, or best, place to look. Objective of measure (reducing emissions, encouraging technology etc.) must be clear, otherwise other types of investment can be expected to ask for similar treatment.	Recommended as a Quick Start Item in December 1998. Proponents would like to encourage an effort to help startup companies take advantage of CCA and to develop a method whereby the adverse investment and product price effect of the Specified Energy Property Rules can be mitigated in order to achieve equivalent after-tax positions for climate-friendly investors passive or active. This is a complex matter that involves fundamental tax principles.

PREPARATORY MEASURES (2000-2003)

Name of Measure	Nature of Measure/ Impacts	Costs to Implement	Level of Table Member Support (Subject to Caveats)	Caveats on Some Table Members' Support	Comments
9B) Shift the basis of property taxation from capital to revenue or production	Preparatory. Removes tax bias against capital intensive generation.		No convergence.	Similar problems as above, could be seen as a precedent for property taxes in general.	Recommended as a Quick Start Item in December 1998. Objective of measure could have significant effect on its acceptability. Would enable developers of no/low-GHG emitting electricity technologies to be taxed on a competitively neutral basis with conventional fossil-fuel based generation.
9C) Demand Side Management	Preparatory.	Unspecified amount of financial support required.	General Support		Buildings, Municipalities Tables developing specific detailed efficiency measures.
9D) Increase coal royalties	Preparatory. Proponents see the purpose of this measure as designing a level playing field for coal and gas.		General opposition, some support.		Model results show zero effect on GHG emissions. Distorts 'rent gathering' purpose of royalties. Is disguised, partially applied, carbon tax. Creates disincentive to capture and sequestration investment. Unfairly attacks a single sector of the economy.

COMMITMENT PERIOD MEASURES					
Name of Measure	**Nature of Measure/Impacts**	**Costs to Implement**	**Level of Table Member Support (Subject to Caveats)**	**Caveats on Some Table Members' Support**	**Comments**
Credit for Early Action			Support in principle	Should be independently verified, transparent, and for projects where the majority of reductions are in Canada.	Seen as urgent. Designed to achieve significant near term reductions as a step in a transitional, phased approach towards a commitment period. Assist industry in managing the risks of the impacts of future global climate change policy.
Carbon Pricing Mechanism (e.g. tax, emissions trading system) *[Electricity Sector constraint of 94% of 1990 GHG emission levels by 2010]*	Stabilization at 94% of 1990 sector emission levels from 2010 (28 Mt of CO2 equivalent reduction from unrestricted emissions in 2010)	Discounted costs of $3.9 billion over 30 years. (Marginal costs of $12/tonne in 2010)	Mixed support, some reservations.	Do not want electricity sector singled out.	Efficient. Allocation issue needs to be addressed. Need to identify a mechanism to deal with stranded costs. Dollar numbers only reflect the cost of changing the generation mix. Costs to the electricity sector will also depend on changes in other sectors and in the U.S. (e.g. changed electricity exports to the U.S.). Examining these was beyond the mandate of the Electricity Table. Degree of support varies with breadth of application and choice of instrument.

COMMITMENT PERIOD MEASURES					
Name of Measure	**Nature of Measure/ Impacts**	**Costs to Implement**	**Level of Table Member Support (Subject to Caveats)**	**Caveats on Some Table Members' Support**	**Comments**
Generation Quota or Portfolio Standard (Large percentage) *Application of these standards at 3-5% or more for emerging, non-GHG emitting technologies (wind, solar, biomass, geothermal, extra-low-head hydroelectricity, micro-turbines run on renewable resources).*	Table modelled a portfolio standard of 3% of total energy demand in 2005 and 5% in 2010, which resulted in a 10 Mt reduction in emissions by 2010.	A national portfolio standard of 5% of total energy demand by 2010 was modelled which allowed inter-provincial trading and cost $38/tonne (or $4billion over 30 years). A portfolio standard of 3% of total energy demand in 2005 and 5% in 2010 but with no inter-provincial trading was also modelled and cost $76/ tonne (or $8billion over 30 years).	General opposition, some support.		The results of modelling this measure illustrate that technology-prescriptive measures to achieve Kyoto-like reductions cost more than pricing mechanisms when they impose a mix of generation that is different than what would emerge under a pricing mechanism (e.g. $4 billion cost over 30 years for a national portfolio standard to achieve minus 10Mt. Emission pricing gets minus 28Mt for the same cost.) Some environmentalists on the Table were of the view that, with careful design, such a measure.would be appropriate As a potential component of the mix of measures for supporting emerging, non-emitting technologies, a small generation quota or portfolio standard does have general support as a preparatory measure.

REFERRED MEASURES					
Name of Measure (Measure Reference Number and Page in Main Report)	**Nature of Measure/ Impacts**	**Costs to Implement**	**Level of Table Member Support (Subject to Caveats)**	**Caveats on Some Table Members' Support**	**Comments**
Financial Support for New Low-GHG Augmenting Electricity Generation.			Support in principle.		Option recommended to the NAICC-CC in December 1998 as a potential 'Quick Start' element of the Climate Change Implementation Strategy.
Support for Strengthened Voluntary Action (JMM call for everyone to participate in VCR)			Support in principle.		Mandate of Enhanced Voluntary and Credit for Early Action Tables. Support for option conveyed to NAICC/AMG. Seeking a risk management level of effort.
Enhance VCR			Support in principle.		Mandate of Enhanced Voluntary Table. Support for option conveyed to NAICC/AMG.
Encourage Industry/Government/NGO Partnership on Joint Implementation and Clean Development Mechanism			Support in principle.	Provided that the majority of reductions occur domestically	Mandate of Kyoto Mechanisms Table. Support for option conveyed to NAICC/AMG.
Early Establishment of Bilateral Emissions Trading with the U.S.			Support in principle.	Provided that the majority of reductions occur domestically	Mandate of Kyoto Mechanisms Table. Support for option conveyed to NAICC/AMG.
Strengthen consumer information Programs			Support in principle.		Mandate of the Public Education and Outreach Table. Support for option conveyed to NAICC/AMG.

MEASURES PROPOSED, BUT NOT ANALYZED FOR LACK OF SUPPORT					
Name of Measure	**Nature of Measure/ Impacts**	**Costs to Implement**	**Level of Table Member Support (Subject to Caveats)**	**Caveats on Some Table Members' Support**	**Comments**
Provincial Caps of non-GHGs			Generally opposed as a GHG measure.	Indirect connection to GHGs	Some environmentalists on the Table were strongly in favour of this measure
Time limit for the recovery of stranded costs					Table members were divided on whether this would have an impact on GHG emissions
Standardize technology to reduce infrastructure				No GHG connection, indirect electricity connection	
Limit coal imports to Ontario & Manitoba					Some members were concerned that there might be potential trade implications
Interim Cap (e.g. firm commitment for, say, 2002 or 2003)					Demonstrate commitment. Phased approach to Kyoto. Strong support from some Table members

Section 4 Preparatory Measures

Candidate measures were identified by Table members, and are summarized below. Model results are available for several of the preparatory measures, and are discussed in the text. Some measures were deemed to fall under the mandate of other Tables, and were referred to them, as appropriate (see Annex A).

The preparatory measures identified fall into nine categories:

1. General Monitoring
2. Consumer Information
3. Regulatory Efficiency Improvements
4. Plan for Fossil Fuels
5. Plan for Hydro
6. Plan for Nuclear
7. Plan for Emerging, Non-GHG-emitting Technologies
8. RD & D for Longer Term Options
9. Other

Coordination with non-GHG emission control

There is also another "measure" that could be added to the preparatory package. It is not aimed at reducing GHGs *per se*, but at ensuring that regulation of GHGs is co-ordinated with other new regulations on other power plant emissions, specifically of NOx, SO_2 and particulates. Such regulatory coordination would facilitate more economically efficient emission reduction actions at generation facilities, leading to lower costs for electricity producers (and potentially lower prices for consumers).

Requirements for non-GHG emission reductions may vary regionally, and regulatory co-ordination will be most efficient where GHG measures incorporate regional flexibility, as in the case, for example, of GHG national caps and trading. In addition, future emission targets should be identified early, so that electricity generators can incorporate them in their planning.

1. Emission Reporting

Phased approach to implementing a comprehensive emission reporting system.

Reporting of GHG emissions or emission content of fuels consumed in a way that supports pre-commitment period and commitment period measures.

Background

There are two separate, but related needs for a comprehensive emission reporting system: international reporting of Canada's emissions inventory, and reporting for implementation of domestic policy measures.

For international reporting, Canada, as an Annex I Party to the UN Framework Convention on Climate Change, is committed to compiling and reporting annual emission and removal inventories of greenhouse gases and to track progress in meeting emission reduction targets. The Kyoto Protocol requires internationally-agreed measurement guidelines for reporting and tracking purposes. UNFCCC inventory-reporting guidelines, currently being negotiated will likely require increased transparency, and improved data and verification procedures. In addition, under Article 7 of the Kyoto Protocol, appropriate emission inventory allocation mechanisms are needed to link and attribute domestic emission reductions to the internationally reported inventory.[1] The Canadian GHG Emissions and Removals Inventory (CGERI) is developed and compiled by Environment Canada on a national, provincial and sectoral basis, without attribution to any individual source. The methods used to develop the net emissions strive to use published data, such as energy data from Statistics Canada, but also rely on data collected by industry, or developed using models and in-house engineering. The use of company information on GHG emissions is now more for verification than for actual monitoring purposes.

For domestic policy purposes, the voluntary reporting under the VCR is an important source of emission data. However, due to data limitations, it does not allow for proper attribution and transparency in both domestic and international reporting, which are likely requirements under the Kyoto Protocol. The voluntary nature of data collection usually provides less overall coverage and attention to detail than is likely to be required. Currently, much of the information is provided on a project basis, rather than at the company level, which would be required to support these initiatives.

The coverage of a comprehensive reporting system for domestic policy purposes is linked to potential domestic policies. For example, entity-level reporting of emissions may not be necessary if certain policy instruments are used to the exclusion of others, such as a tradable permit system based on the carbon content of fossil fuel products. This could be administered on the basis of fuel sales and a set of fixed coefficients for carbon content.

Implementation

Inclusion of the electricity generation sector in a phased approach to designing and implementing a comprehensive monitoring and reporting of GHG emissions.

Agencies responsible

Environment Canada, with the support of provincial agencies.

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1 Monitoring, Reporting and Review of National Performance under the Kyoto Protocol, OECD Information Paper, October 1998

Policy linkages to other sectors

Emission reporting at the entity level would be required for those policies that would apply to entity level emissions. The early phases of reporting should cover a wide range of sectors to determine the different measurement and reporting challenges that need to be addressed.

The cost of providing data may differ somewhat from industry to industry, although there is no reason to expect order-of-magnitude differences.

Economic cost to the electricity sector

The cost of reporting by power companies is not expected to be large. They already report a large amount of the data required for complete accounting of GHGs. However, the information tends to be spread among several departments within utilities, and is often based on inconsistent assumptions. The data need to be made consistent and the reporting streamlined.[2]

International trade implications

Likely negligible, unless Canada's trade partners misuse the information to erect trade barriers.

Experience in other countries

Data collection procedures for national inventories vary widely among countries and are closely related to the resources available for the inventory task. Normally, they are dependent upon the national statistical systems. Where data are not collected for other reasons, such as in the case of industrial emissions of SF_6, HFCs and PFCs, the emitters may be the only sources of information. Where point source data is collected, some EU countries use the same system for GHGs as they do for contaminants.

Necessary conditions for implementation

Implementation of this measure should begin with a plan outlining a phased approach leading to broad coverage at the end of a three-year period. It should begin with a relatively small sample of entities in a variety of sectors, to determine the measurement and reporting challenges that need to be addressed and the links between data requirements and measures in both the pre- and post-commitment periods. The plan should avoid unnecessary duplication and administrative burdens on participants by streamlining existing reporting to governments.

Analysis: Table Views

The objectives of this measure were seen to be:

- to support a more rigorous treatment of voluntary activity under the VCR and EcoGeste programs;
- to support credit for early action
- to support Measure 2 (Retail disclosure of generation mix or emissions);
- as a precursor to auditable emission trading – especially the creation of defensible baselines; and
- to support Canadian participation in international fora, including those developing the Kyoto mechanisms, through better understanding of the issues around emission reporting.

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[2] *Greenhouse Gas Decision Tools, Tom Wilson, EPRI Journal, Volume 20, Number 3*

Members pointed out that the great majority of emissions are reported voluntarily through the larger generation firms and utilities, and that the sector has been among the most forthcoming in this regard. However, some indicate that there remain inconsistencies between different data sets and that a significant number of independent producers do not report. It appears that a higher degree of completeness and rigour would be required to support the objectives above.

Confidentiality is an increasing concern, as the industry structure becomes more competitive. Producers may be concerned about public reporting of production or fuel consumption, or of numbers from which conclusions about production or fuel consumption could be inferred. Independent producers, in particular, express reluctance to be required to report unless the appropriate safeguards are in place, such as suppression in public reports of statistics derived from a small number of firms.

The VCR, being voluntary, was not seen as the appropriate inventory-gathering mechanism for a comprehensive reporting system. One benefit of reporting is that it brings management's attention to emission risks and opportunities.

The Table was also concerned that the electricity sector would be specially targeted in a reporting system, either because it is reporting so well already, or because it is relatively easy to do so (*e.g.* because of the relatively small number of plants). It is important that the early phases of this effort extend to a wide range of sectors to be able to move in a balanced way toward a comprehensive system.

The Table strongly supports this measure as an essential building block that should be operating smoothly before the commitment period, with the exact timing based in part on what others in the international community are doing. It is important to take a phased approach along a path that does not impose reporting obligations that are not necessary.

2. Consumer Information

Disclosure of the generation mix /environmental attributes to electricity customers.

Require disclosure to customers by electricity retailers of their generation sources and or environmental impacts.

Background

This measure is designed to ensure consumers have information about the characteristics of the generation for which they are paying so that they can make informed decisions about their electricity consumption. In jurisdictions with retail monopolies, disclosure or labelling provides information that customers can use to choose the type of electricity generation preferred and how much electricity to consume. In jurisdictions with retail access, it also provides customers with information useful to their choice of supplier. Some regard this as analogous to nutritional labelling of food products.

This measure would also increase public awareness of climate change issues and how decisions in everyday life affect GHG emissions; similar GHG labelling should be implemented in other sectors of the economy, such as transportation, buildings and industry, to ensure that electricity sector is not unduly targeted in the public eye.

Disclosure may be based on information either at the product or company level. For instance, suppose a firm's resources are 50 percent nuclear and 50 percent natural gas. Under the company approach, it must sell a 50-50 mix of generation to all of its customers. Under the product approach, it could sell a 100 percent natural gas mix to half its customers and an all-nuclear mix to the other half. Research suggests that customers understand and are comfortable with both approaches. However, the product approach creates a greater linkage between investment and operation decisions of sellers and the stated preferences of buyers. By contrast, under the company approach, the development of new products only minimally affects the average mix of suppliers. Disclosure rules may require either generation mix, or emissions/impacts to be reported, or both.

At present, only Ontario plans to require disclosure at the retail level. The *Ontario Energy Competition Act* (1998) authorises disclosure regulations covering both generation type and "the nature and quantity of prescribed contaminants". In preparation for the retail marketing of electricity, the Ontario government has proposed a mandatory and uniform label showing the energy supply mix on all promotional materials. Any retailer who makes claims about the type of power source or any environmental effects of the production or use of electricity would have to disclose the projected mix of the electricity generation. The government also proposes to develop an environmental information fact sheet to be distributed to customers in advance of the establishment of a retail market for electricity in 2000. In addition, it intends to develop more detailed regulations to track, collect, and make available information on the environmental attributes of electricity generation to consumers once the market opens.

Implementation

The two basic requirements for information disclosure are accuracy and the presentation of information in a useful way. In retail systems, accuracy requires transaction tagging or certification ("electron identification"), information systems, measurement conventions and enforcement of truth-in-advertising laws. There is a trade-off between an easy-to-use but potentially simplistic system on the one hand, and a precise and comprehensive but difficult to understand system on the other. Market research in both electricity and other products suggests that disclosure should be simple and uniform, so that consumers are not overwhelmed with information.

Consumer protection and utility regulation are primarily provincial matters. It will be important for the federal government and the provinces to work together to harmonize labelling requirements. This would become increasingly important if competition or environmental policies increase interprovincial or international trade.

Agencies responsible

In jurisdictions with retail access, disclosure requirements may be addressed directly in legislation or may be considered to fall under consumer protection law, one of the primary aims of which is to prevent false claims by competing firms.

Linkages to other policies

Disclosure and certification alone cannot ensure improvements in environmental quality. Public education complements disclosure and may increase the impact of labelling, as is the case with nutritional labelling, energy consumption stickers for appliances and other areas.

Certification of environmentally friendly power supply (*e.g.* an eco-logo program) is simplified when the standards are unambiguous in terms of the information to be disclosed.

Jurisdictions that adopt renewable portfolio standards or system charges that fund specific environmentally-friendly resources must take care to avoid double-counting, by distinguishing resource investments or purchases to comply with these mandates from supply offered under other, market-driven programs. Otherwise consumers may be asked to pay a premium for actions that an energy supplier is required to undertake anyway.

It may be permitted to allow disclosure labelling to reflect GHG offsets when there are accurate and reliable estimates of emission reductions.

Uniformity between provinces in their disclosure rules becomes more important as interprovincial electricity trade increases, if customers are to have a basis of comparison between out-of-province and in-province suppliers. (The same applies to states, vis-à-vis provinces). Standardisation of the label would also help marketers with supply contracts in several jurisdictions. (See also Regional Effects below).

Inter-jurisdictional accounting issues

Differences in disclosure requirements between trading jurisdictions can create opportunities to circumvent or distort disclosure. If comparable labelling procedures are not available between trading jurisdictions, imported electricity is typically rated at the average of the plants in the exporting jurisdiction. This ensures that firms do not claim to export only "dirty" power to a jurisdiction without disclosure, while claiming environmental credit for a disproportionate amount sold locally.

Economic cost to the electricity sector

Additional sectoral costs associated with disclosure stem from the increased administration required to track the supply of electricity by generation fuel source type. Some information on administrative costs is available from the literature on utility green energy programmes. For example, the (one-time) cost of reprogramming the billing system was on the order of $50,000 to $100,000 at one utility.[1] In retailing jurisdictions, non-utility producers would generally absorb these administrative costs. Provincial utilities would likely pass costs on to all consumers under prevailing cost recovery principles.

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[1] *Weijo, R.O. and D. Boleyn. 1996, "Product Concept and Field Test of Green Marketing Programmes," American Council for an Energy-Efficient Economy 1996 Summer Study, Portland, Ore.: Portland General Electric.*

Regional effects

The predominantly hydro systems are interconnected to a significant degree with neighbouring U.S. states and in general could expand exports if their generation capacity exceeds domestic consumption. Electricity conservation in hydro provinces could contribute to GHG emission reductions by freeing up generation for export and displacement of fossil generation in neighbouring systems.

The consumer information measure needs to be integrated with other public education programs to send a general message about the benefits of energy efficiency and conservation, independent of the type of generation.

International trade implications

Canada-U.S. differences in disclosure requirements could have implications for bilateral electricity trade if the inter-jurisdictional accounting rules were not harmonised.

Experience in other countries

In March 1997, the public utilities of the six New England states developed the "NECPUC" (New England Committee of Public Utility Commissioners) rule for uniform and effective disclosure in the retail sale of electricity. The rule became the basis for most or all retail disclosure laws now in effect or under consideration in the U.S. The states that now have mandatory disclosure as part of electricity market restructuring include Maine, Massachusetts, Vermont and California. Massachusetts and Vermont require both emissions data and generation resource mix to be disclosed, while Maine requires only the latter. California recently legislated an Electricity Source Disclosure Programme.

It is too early to tell what the impacts of disclosure will be for the uptake of emerging non-GHG technologies. However, from various studies[2], it has been shown that consumers had similar reactions to the question of what information should be disclosed:

- Most participants wanted a variety of information on which to base their choice of a supplier. Although much of the original policy interest in information disclosure focused on environmental issues, focus groups made clear that information disclosure is a broader consumer protection issue.
- Focus groups were quite consistent in the factors important in the choice of supplier. These were price, service reliability, environmental information (including fuel mix and emissions), contract terms, company track record and customer service record.
- Price was usually the most important factor. Even though suppliers might use different pricing structures for different products, participants wanted to be able to compare prices in terms of average cents per kWh.
- When presented with both fuel or resource mix and emissions information, participants recognized that they did not represent the same thing, and they wanted to see both pieces of information.
- There is a willingness to pay a small amount to receive standardised information and an understanding that the cost would be included in the price of the electricity.

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[2] *e.g.* The National Council on Competition and the Electric Industry Synthesis Report: A Summary of Research on Information Disclosure, *Consumer Information Disclosure Project, April 1998)*

Necessary conditions for implementation

Implementation requires the ability to monitor the generation mix of electricity retailers. A grid-connected customer's electricity cannot be traced to any specific plant or plants within the set of generators on the grid. Therefore disclosure can only pertain to the characteristics of generation sources with which an electricity retailer has contracts. These may be quite complex – for example the supply source(s) contracted could vary with prices, maintenance outages and transmission congestion.

Areas for further research

It would be worthwhile to articulate a comprehensive, integrated consumer/public information strategy and the place of product labelling in that strategy.

Analysis: Table Views

Electricity may be generated by technologies with widely varying GHG emission effects. Electricity is special in this sense, relative to oil products and natural gas, the other principal GHG-emitting retail commodities. Therefore environmental labelling of electricity permits a wider range of environmental choice. It has no coercive aspects; the mechanism has been shown to work in practice; and it is now under construction in Ontario.

The measure can be applied to all systems. There is no problem foreseen in having the rules be voluntary in provinces with retail monopolies and mandatory in others. However, an increase in interprovincial electricity trade could be part of a least-cost response to a binding emission constraint, increasing the importance of harmonised disclosure rules.

Mandatory disclosure of generation mix or its environmental attributes is common in jurisdictions with retail open access. Mandatory disclosure ensures that environmentally-differentiated electricity contracts can be transparently presented to the retail market, enabling customer choice. Retail monopoly utilities may also offer "climate-friendly" rates as an option and customers may alter consumption levels based on label information even in the absence of such rate differentials. Therefore the Table sees this measure as having a potential greenhouse gas impact within all forms of market structure.

Labelling laws are typically explicit about the form and medium in which information is to be presented. In itself, public availability of information is not sufficient. A number of Table members felt strongly that the information would be more effective if it was provided with the retail consumers' bill.

The measure is linked to, but distinct from Premium Electricity Rebates (Measure 7D), which assumes the availability of separate rates, contracts or prices for climate-friendly retail electricity. Disclosure would be necessary for implementation of Measure 7D. The measure is also linked to the activities of the Public Education and Outreach Table.

Although there were some reservations about how much information customers want to see, there was strong support for this measure. The Table would support other Provinces following Ontario's lead where significant environmental choice may be considered available.

Some table members strongly feel that similar GHG labelling should also be implemented in other sectors of the economy, such as transportation, buildings and industry, to ensure that electricity sector will not be unduly targeted in the public eye.

3. Regulatory Efficiency Improvements

3A) Improve Regulatory Efficiency – Major Projects

Reduce regulatory uncertainty for power plants that will meet Canada's environmental, social and economic policy objectives by ensuring that environmental review and other approval processes are as open, clear, fair, timely and efficient as possible, while ensuring effective environmental protection..

Background

Meeting Kyoto objectives is expected to require a significant amount of new low GHG-emitting generation. Clear and efficient environmental and other review processes are necessary to ensure the timely completion of such projects. However, any change should still ensure that the processes provide effective environmental protection.

The objective of this measure is to remove delays and uncertainty, which impose unnecessary costs and delays on developers.

Some new economically and environmentally acceptable generation projects may not proceed because of uncertainty in the duration and requirements of the review, as well as possible after-the-fact legal challenges. These uncertainties have relatively more impact on hydropower projects because they involve many federal and provincial departments as well as regional and local authorities. Moreover, large-scale hydroelectric projects disproportionately attract the attention of regulators and intervenors when compared to multiple smaller projects which together would be of the same scale. In addition, investor sensitivity to regulatory uncertainties is high, given these projects' scale, capital intensiveness, long lead times and very long life-spans.

Implementation

This measure could be implemented immediately. Rapid implementation would ensure that new plants can contribute to GHG reduction during the Kyoto first budget period, particularly in the case of hydro.

Agencies responsible

The principal federal bodies involved or concerned are Environment Canada, Natural Resources Canada, Fisheries and Oceans Canada, the Canadian Coast Guard and the Canadian Environmental Assessment Agency. Provincial agencies vary by province.

Economic cost to electricity sector

Clarifying the approval processes would assist in encouraging expansion where and when it is economic, provided that Canadian objectives in the areas of social and environmental policy are maintained. All other things being equal, the measure would be expected to reduce costs of regulation as well as bring into being some economic projects that would not otherwise have been built.

Economic effects on other sectors

Canadian generation/transmission plant suppliers and constructors would benefit through additional local activity and better international competitiveness. The majority of the development expenditures would be for Canadian goods and services, thus stimulating the domestic economy.

Regional effects

Regional spin-offs for hydropower would occur in Québec, Newfoundland, Manitoba and British Columbia. Local enhancement measures can increase spin-offs in sub-regions that require such opportunities.

International trade implications

New low GHG-emitting power generation would in some cases be exported to the United States. Depending on the international regime in place, Canadian exporters could negotiate the value of the consequent GHG reductions.

Necessary conditions for implementation

The terms of reference for environmental review panels and their guidelines would ensure that abatement of GHG emissions is properly accounted for. This may require appropriate legislative and/or regulatory changes.

EIA practitioners and reviewers would also have to take into account lessons from follow up studies and research on the impacts of hydro project and mitigation on issues such as water quality, mercury and fish.

Further Elaboration

Proponents of this measure have the following views and recommendations for legislative and regulatory improvements:

1. Clarify unclear concepts in the current legal framework such as:

In the *Canadian Environmental Assessment Act* (CEAA):

- "Cumulative impact assessment": The CEAA requires every assessment to consider "the environmental effects of the project, including any cumulative effects that are likely to result from the project in combination with other projects or activities that have been or will be carried out." Yet the CEAA gives no further definition or description of cumulative effects. Although cumulative effects are a recognized concept in and component of environmental assessment, they may easily be misunderstood or used to slow down the process. It is therefore important that boundaries for cumulative effects be established. In 1997, the Canadian Environmental Assessment Agency produced a draft guide for cumulative assessment. The guide may be described more accurately as a discussion document without any critical comment on past experience.
- "Achieve sustainable development.": The Act provides no definition of this objective.
- The definition of project as: "... a) in relation to a physical work, any proposed construction, operation, modification, abandonment or *other undertaking in relation to that physical work* ...": The expression in italics requires clarification.
- "Needs and alternatives": The extent of this justification and analysis has never been clearly defined. Should it be local, regional, national or international? Guidelines are required. In addition, guidelines should appropriately recognize low GHG-emitting generation sources.
- "Spirituality" as an aspect of "environment": The CEAA must explore alternative avenues for including aboriginal groups in multi-jurisdictional assessment processes.

In the *Fisheries and Ocean Policy*:

- "No net loss of habitat": This concept is unclear and not applied in a uniform way. Considering the inevitable modification of habitats due to the presence of a project, mitigation and compensation measures outside the affected area should be more systematically incorporated as part of the solutions.

- "Multiple use of water-ways": It is essential to meet the need to balance uses of the water resources. However, the *Policy* provides no recognition of the realities of multiple use planning.

In *Bill C-32*, the *Canadian Environmental Protection Act* (CEPA) Review:

- "precautionary principle." Although CEPA is not at issue directly in discussions on environmental review processes, unclear concepts introduced into this bill, such as the precautionary principle, tend to influence decision making in general. In fact, the Canadian definition proposed in Bill C-32 is not the one referred to in the international agreement signed by 150 countries and Canada. This is another potential source of confusion and litigation risk.

2. Limit discretionary powers and provisions in the EIA processes.

   The *Law List Regulation* is a key piece of regulation that triggers projects under the CEAA. The principal triggers require authorizations under the *Fisheries Act* (e.g., sections 22 [1][2][3], 32, 35[2] and 37[2]) and *Navigable Water Act*. These sections are problematic because of expressions such as "... the person shall, on the request of the Minister" or "... the Minister or a person designated by the Minister is of the opinion that...". The *Law List Regulation* needs to be revised and the triggers streamlined for projects having potential environmental impacts warranting assessment. Moreover, since large-scale hydroelectric projects will remain more prone to being assessed, triggers should be more foreseeable. Accordingly, regulations should clarify how and when ministers can intervene. As for the *Navigable Water Act*, regulations should specify which rivers are to be considered navigable so that courts are not left to decide case by case.

3. Focus EIA processes on key issues by adjusting or modifying critical legal mechanisms:

- Guidelines are more likely to meet high-quality and professional standards if prepared by people with expertise in assessment and the specific territory affected rather than the general public. Public hearings on guidelines should be focused on defining major issues, rather than on new incremental details to address in EIAs. The current focus often leads to encyclopedic studies having little value-added.

- Public hearings should be carefully focused on defining acceptable mitigation measures, as well as whether a project should proceed or not.. Often the hearings discuss policy issues outside their mandate (*e.g.*, resource management and allocation in the context of cumulative effect assessment). These issues are addressed more appropriately by governments than proponents, particularly in a competitive marketplace.

- Specified time frames for each critical step in the processes, namely the issuance of guidelines, public hearings, and decision making by responsible authorities under CEAA.

4. Harmonize decision-making and respect provincial jurisdictions.

- Federal departments must coordinate their efforts. Federal legislation and rules must deal with issues on a comprehensive basis (such as the issue of including the multiple use of waterways in the *Fisheries Act*).

- Provincial and federal processes, which often have fundamentally different trigger mechanisms and approaches, must be harmonized. Most provincial EIA processes start at the planning phase of a project, while the federal CEAA process starts at the construction phase. Environmental assessments are most effective if undertaken in the early planning stages for a project. During these stages, the involvement and commitment of federal authorities under the CEAA are critical to the proponent's expectations regarding base line conditions, guidelines, cumulative effects, and so on.

Hydroelectric development is constitutionally a provincial jurisdiction. Although Canadian courts have recognized the right for the federal government to intervene when its jurisdiction over the environment is concerned, this should not be used as an indirect means of regulation. Harmonizing EIA processes should not only establish a one-window approach but also address this fundamental problem.

Analysis: Table Views

Analysis of Measure 5 below shows that hydroelectric development may play an important role in meeting a binding emission reduction requirement.

The importance of the measure for climate change mitigation policy may also be illustrated by assuming no new hydro is allowed in both carbon-unconstrained and carbon-constrained cases. Costs of supply are higher in both cases than if new large hydro is permitted to occur, but the additional net discounted cost over 30 years of meeting a 94% of 1990-level emission constraint is $5.9 billion if no new large hydro is permitted, compared to $3.9 billion assuming new hydro is available.

The Table generally supports this measure and would like to see higher priority attached to regulatory efficiency issues than is currently in effect. An announcement of the Joint Ministers ("JMM") has also indicated that hydroelectric development was a part of the solution to climate change mitigation in Canada. However, some table members, groups and individuals will have concerns that the enhancements to the review processes could lead to inadequate environmental protection. Effective environmental protection based on meaningful public consultations must be kept as a requirement when implementing this measure. In the view of some Table members, the problem is not so much the lack of environmental protection legislation, but of an apparent lack of will or resources to enforce it. Table support is conditional on the need for consistent and rigorous enforcement of environmental protection laws.

3B) Incorporate greenhouse gas considerations explicitly in the review and approval processes.

Background

Canadian environmental regimes have emerged largely as a result of concerns over local impacts. However, some of the most important current environmental challenges, including climate change, are global in nature. Current environmental regimes are not well designed to address the latter. In practical terms, current regimes impose strict requirements on some electricity options to address local issues, but do not adequately recognize their global impacts or provide solutions to reduce them. In some cases, achieving GHG emissions reductions requires recognition of the impact of the project on global GHG emissions.

Implementation

The primary objective of this measure is to ensure recognition of global benefits in the assessment of the environmental and social impacts of projects. This measure is not proposing that impact reviews under CCEA include a *detailed* GHG analysis, but rather a general recognition of the GHGs emitted or reduced by a project.

Amendments to the Canadian Environmental Assessment Act would be necessary at the federal level. Provincially, legislative changes could also be required, but direction to regulators from their governments may be sufficient.

Regional effects

The measure would benefit provinces with undeveloped hydro and other renewable energy resources.

Analysis; Table Views

The Table had mixed support for the inclusion of GHG emissions in environmental assessments of projects and of the potential of projects to reduce GHG emissions. Some members feel that it would represent an unnecessary addition of a regulatory process in an area to be addressed by national policy. Others believe that the absence of a policy on GHG emissions at the national level would create greater pressure on regulators to deal with the issue of GHG emissions in EIAs. In such a case, guidelines or formal means are necessary to properly address trade-offs between GHG emissions against project benefits, or to ensure they are rolled into project costs.

Some members expressed reservations that the measure would lead to an emphasis of global over local impacts and expressed the view that local priorities are always going to have higher consideration.

3C) Address barriers to inter-provincial transmission construction to allow low/ non-GHG emitting technology to be optimized between provinces.

Background

Currently, throughout Canada and the U.S., there is increasing reluctance to invest in long distance transmission, especially when crossing provincial/state/national boundaries. New interprovincial transmission investment faces uncertainties pertaining to electric industry restructuring and environmental regulation. Potential transmission infrastructure providers are uncertain about timing and likelihood of obtaining government/regulatory approval and about the risk of industry restructuring preventing them from receiving a return on their investment. Recent examples of government intervention to ensure transmission is built when required include Ontario with its decision to expand tieline capability from the U.S. and Quebec, and Wisconsin with its decision to expand tieline capability from the west.

New transmission allows low- or non-GHG emitting supply to displace more-emitting supply in other provinces, thereby, potentially reducing the cost of the least-cost generation configuration. In principle, that low- or non-GHG-emitting supply could be hydro, wind, cogeneration, integrated coal gasification, coal generation with CO_2 capture and storage, nuclear or others. Wind and solar would benefit from access to wider markets for climate friendly electricity and from enhanced ability to "firm up" supply with dispatchable resources in other jurisdictions.

E-MARKAL model results suggest that a significant increase in inter-provincial trading emerges as part of a least-cost solution to an emission constraint in 2020 and beyond, and, in two of the six scenarios, in 2010. (See *Analysis; Table Views*, below). The model also suggests that a constraint allowing no transmission construction would increase the discounted costs (through to 2030) of complying with a 94% of 1990-level emission constraint by up to 30%.

This measure should play a role in Canada's strategy but requires further consultation to decide what transmission, where, and the specific form of support. Any environmental impacts of transmission line development would have to be taken into account through the appropriate assessment and review mechanisms. Taxpayer support for inter-provincial transmission infrastructure could be implemented in a variety of forms: loan guarantees, direct contributions, build/leaseback, or a federally/provincially owned Transco which recovers its investment by means of user tariffs. However these measures run counter to some jurisdictions' approaches.

Implementation

If undertaken early, the measure would ensure that new transmission and generation could contribute to GHG reductions in a timely fashion. Given that new hydro developments can have up to a lead time of 10 years, the measure would have to be implemented after a consultation period of not more than 2 years in order to contribute to reductions in the 2008-2012 period.

Agencies responsible

Transmission is a regulated entity in all market structures. Therefore the essential agencies are governments and utility regulators. At the federal level these are: Departments of Environment and Natural Resources and the National Energy Board; and at the provincial level these are: Ministries of Environment and of Energy and provincial regulators

Regional effects

Some provinces (Quebec, Manitoba, Newfoundland and BC) likely would experience the bulk of the hydro expansion. Other forms of new generation would be distributed differently. Thus the need to develop additional interprovincial infrastructure would vary by region. The E-MARKAL model runs suggest that transmission from Quebec and Manitoba into Ontario would be the primary new links, with corresponding impacts in those three provinces. In the scenarios assuming inexpensive geological sequestration, Alberta also benefits by exporting power over new lines.

Economic cost (or benefit) to electricity sector

The measure would be expected to improve the efficiency of competitive electricity generation markets by reducing potential market power in relatively isolated provincial grids. Increased inter-provincial transmission would also increase system reliability and energy security, thereby reducing problems such as experienced recently in Alberta and Quebec.

International trade implications

The measure addresses mainly expansion of hydro to supply Canadian demand. However, it often may be more economic to export to adjoining states in the U.S. rather than provinces in Canada, one factor being the inadequate transmission infrastructure between provinces. For a number of reasons, energy trade tends to be much larger North-South with the U.S. than East-West with Canadian entities; inter-provincial transmission infrastructure support could assist in achieving a different balance.

A second trade implication is that increased hydropower development would assist Canadian suppliers in enhancing their experience and competitive position internationally.

Necessary conditions for implementation

Two essential conditions are negotiated federal/provincial arrangements and funding of initial support.

Analysis; Table Views

The model results suggest that a significant increase in inter-provincial trading emerges as part of a least-cost solution to an emission constraint in 2020 and beyond, and, in the Composite and No-Bruce-A scenarios, in 2010. Changes in inter-provincial trading are basically driven by Ontario's needs, especially without Bruce A and, in the Composite Case, by higher overall demand as well. New transmission investment that is induced by emission constraints in 2020 ranges from 1.8 GW in the Base scenario to 4.6 GW in the No-Bruce-A Return scenario (on top of business-as-usual investments of 1.8GW and 1.9 GW, respectively, in that year). Hydro would be the main additional generation resource in all cases.

In all scenarios except for the ones with low-cost CO_2 capture and storage, Quebec and Manitoba supply (hydro) electricity to Ontario. In the scenarios with low cost CO_2 capture and storage supply from these two provinces reduces to about half, and is replaced by electricity from Alberta. Alberta also exports to BC under these scenarios.

For example, model results show, in the No-Bruce-A Scenario, a 20%-below-1990-level-carbon-constraint-induced transmission construction of 40 MW between Alberta and Saskatchewan, 1380 MW between Manitoba and Ontario, and 3200 MW between Quebec and Ontario, all in 2020.

The model was also run with the assumption that no new interprovincial transmission would be built. In this case the net cost of complying with a constraint 94% of 1990 levels increases by $1.3 billion, or 30% over the transmission-unconstrained case.

The Table generally supports this measure, as it is intended to make available lower-cost generation configurations whether or not GHG emissions are constrained. However, some Table members wanted to emphasize that differentiation be made between government facilitating the further expansion and health of the electricity industry in Canada for the benefit of Canadians, and government intervening in the market place. They felt that the suggested incentives could become a serious obstacle to the further restructuring of the electricity industry in Canada.

Any projects planned must be environmentally and socially acceptable, and provide for meaningful public consultations. As well, support for this measure hinges on how it is financed.

4. Plan for Fossil Fuels

4A) Financial support for research, development and demonstration: capture and geological storage of CO_2.

Federal and provincial governments to provide financial support for research and development of technologies to capture and store CO_2 from fossil generation with an objective of reducing CO_2 capture costs to \$20/tonne or a significant reduction in CO_2 emissions.

Background

A substantial reduction in GHG emissions could be achieved by capturing CO_2 at large point sources, such as coal-fired electricity generating stations. The captured CO_2 can then be compressed, transported, and injected into deep underground reservoirs for long-term storage.

The technology for the capture and storage of CO_2 is relatively new. Licenced processes which currently exist were originally established to provide CO_2 as a chemical feedstock for industry, and not for CO_2 storage, and are based on absorption or adsorption to 'scrub' CO_2 from the flue gas stream. It is also possible to extract nitrogen from air, add CO_2 from fuel combustion to the remaining oxygen and burn fuel in the resulting mixture, producing a near-pure stream of CO_2. An alternative approach – pre-combustion decarbonisation –uses a fossil fuel to make an intermediate hydrogen-rich gas, where CO_2 capture is an integral part of the process. The hydrogen-rich gas is then burnt to produce energy. Other technologies, based on membranes or cryogenics, could be developed, to be used alone or in combination with the other capture technologies.

CO_2 capture at power stations incurs significant costs and uses substantial amounts of energy. Current R & D is focused on cost reduction and net emission reduction efficiency[3]. A comparison of pre- and post-combustion decarbonisation technologies shows that they are roughly equal in acceptability and applicability but differ on a cost basis. The cost of CO_2 capture and storage in a post-combustion setting where flue-gas scrubbing is used is 1.5 - 2.0 ¢/kWh while pre-combustion synthesis gas clean-up is less at 1.0 – 1.5 ¢/kWh.

On the storage side, Statoil of Norway initiated the first commercial-scale system dedicated to CO_2 storage in 1996. The company has since been injecting about one million tonnes of CO_2 per year from the Sleipner West gas field into a deep saline formation about 800 m beneath the bed of the North Sea. Costs of the operation are approximately U\$15/tonne of CO_2 avoided[4]. Also, large-scale storage of CO_2 has been profitably used in the United States in projects to enhance oil recovery from depleted oil fields and to enhance recovery of coalbed methane (CBM) from deep coal seams. These technologies can be used wherever the appropriate geological formations exist. Productive use of the CO_2 would provide lower cost disposal options. Possibilities include use for EOR, CBM, or chemical feedstock. However, the market for CO_2 as chemical feedstock is limited, and its overall contribution potential is small. EOR and CBM provide the greatest opportunities where suitable geological structures and economic conditions exist.

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[3] Abatement and Mitigation of Carbon Dioxide Emissions from Power Generation, *PowerGen 98 Milan Conference Paper by Paul Freund, IEA Greenhouse Gas R&D Programme, June 1998*

[4] The Economics of CO_2 Capture, *Paper presented at GHGT-4 at Interlaken, Switzerland, 30 August – 2 September 1998 by H.J. Herzog, Massachusetts Institute of Technology (MIT) Energy Laboratory.*

Coal-bed methane (CBM), EOR, gas reservoirs, and aquifers in Canada

In the Western Canada Basin, the technically recoverable CBM resources are substantial, estimated at 3.8 to 7.4 Tm^3[5] However, conventional CBM development in western Canada has experienced poor test results.[6] A one-well, industry/government-funded CO_2 sequestration test is currently underway by the Alberta Research Council. This R&D project is expected to be a useful test of coal seam sequestration in basins with geologically more typical settings compared with the exceptionally favourable San Juan basin in the U.S., where CBM production is currently taking place.[7]

Several studies have looked at the potential for CO_2 capture and use for EOR in Western Canada. Probably the largest study to date was conducted in the early 1990s by the then Alberta Oil Sands Technology and Research Authority (AOSTRA) and a consortium of industry and government agencies.[8] The study reviewed CO_2 capture from a variety of major emission sources, CO_2 flooding of a variety of reservoirs representative of oil fields in Alberta and Saskatchewan, and storage in a depleted gas reservoir. The economics of implementing such projects were evaluated based on the costs of CO_2 capture and delivery to the field, and the benefits arising from EOR. The specific target was to sequester 18.3 million tonnes of CO_2 per annum.

McCann and Associates completed a follow-up study in 1998 under the sponsorship of the Alberta Chamber of Resources and a consortium of industry and government agencies[9]. This study included a more complete inventory of smaller, present and future sources of CO_2 supply in Alberta and the economics of CO_2 recovery from them.

Also last year, the economic potential of the use of CO_2 in enhanced oil and coal bed methane recovery in Western Canada was evaluated in a joint Alberta Research Council/Nova Chemicals study[10]. The study quantified the potential revenue associated with the storage of CO_2 according to both EOR and CBM schemes. The study did not evaluate and screen individual oil fields and CBM formations, nor did it have access to actual field production profiles. Instead, the economic calculation was based on parameters describing field/operating characteristics, with each parameter covering a typical range of uncertainty.

Finally, the potential for the development of a province-wide CO_2 / EOR infrastructure in Alberta was evaluated in a very recent paper by Edwards.[11] CO_2 sources and locations, oil reservoirs and their locations, potential oil recoveries, and capital costs of pipeline and field infrastructures were all included in the evaluation. Assuming a fixed cost for capturing CO_2, rates of return for a large-scale CO_2 flooding scheme were calculated.

Between 1993-95, the Alberta Research Council carried out a large research project, funded by a consortium of government agencies and industry, to provide the theoretical and numerical proof-of-concept of hydrodynamic and mineral trapping of CO_2 injected into deep aquifers in the Alberta Basin.[12] The study concluded that the potential for this type of storage was essentially 'unlimited'. The study did not include an economic evaluation, but follow-up communication indicated a CO_2 injection cost (incl. field infrastructure) of approximately $7/t.

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[5] CO_2 Sequestration in Deep Coal Seams:Pilot results and Worldwide Potential, *paper presented at GHGT-4 in Interlaken, Switzerland, 30 August - 2 September 1998 by Scott H. Stevens, Vello A. Kuuskraa, Denis Spector, and Pierce Riemer, IEA Greenhouse Gas R&D Programme (http://www.ieagreen.org.uk/pwrghgt4.htm)*

[6] Ibid.

[7] Ibid.

[8] CO_2 Disposal Study, *Alberta Oil Sands Technology and Research Authority, April 1993.*

[9] Towards a CO2 Utilization Action Plan for Alberta, *T.J. McCann and Associates, prepared for the Alberta Chamber of Resources, September 1998.*

[10] Injection of CO_2 for Enhanced Energy Recovery: Coalbed Methane versus Oil Recovery, *Paper presented at GHGT-4 in Interlaken, Switzerland, 30 August - 2 September 1998, by S. Wong, C. Foy, W. Gunter and T. Jack*

[11] CO_2 in Alberta - A Vision of the Future, *Paper presented at the 1999 CSPG and Petroleum Society Joint Convention, Calgary, Alberta, June 14-18, 1999, by K. Edwards, Chevron Canada Resources.*

Table 1

Summary of available cost/revenue study data (in $Cdn) of CO_2 capture and storage by EOR and CBM in Western Canada

Study	**AOSTRA (1993)**	**McCann (1998)**	**Wong et al. (1998)**	**Edwards (1999)**	**Misc.**
Costs of capture, treatment and compression					
Conv. coal (PC) plants, solvent absorption process	$51-54/t (social appr.) $57-60/t (norm. bus. appr.)	$24-48/t (14.2 Mt/y avail. from selected Alta plants)	Not considered	$28/t [13] (49.1 Mt/y available from major Alta plants)	$24-28/t [14] $30/t [15] $20-28/t [16]
O2/CO2 recycle	$53/t				$20-25/t [17]
IGCC	$25/t				
Oilsands plants		$24-48/t (6.2 Mt/y)			
Hydrogen plants		<$19/t (5.5 Mt/y)			
Cost of pipeline transportation					
Alberta	$2/t	$0.40-1.00/t	Not considered	Included in ROR calc.	
Saskatchewan	$0.58-0.76/t				
EOR Economics (see notes below for assumptions)	Affordable Price of CO2 / Volumes Sequestered	Affordable Price of CO2	Affordable Price of CO2	Rate of Return (ROR)	Affordable Price of CO2
Target volume to be sequestered	18.3 Mt/y	Not considered	Not considered	6.7 Mt/y	
Economics based on production simulation of:	6 prototype reservoirs	Not considered	Not considered	1 prototype reservoir	
	$34/t : 9.8 Mt/y $19/t : 2 Mt/y $0/t : 6.2 Mt/y	$28/t, estimated by field operators. Key parameters are oil price and royalty regime.	$22/t	ROR>12% if oil price > $23/bb, royalties < 10%, CO_2 purch'd at $28/t	Viability: [18] $14-20/t high ,$20-25/t avg., $25-35/t,. limited Weyburn field: ~$28/t
CBM Economics			Affordable Price of CO2		
			$2; 10; 16; 29 /t at gas prices of $1.8; 3; 4; 6 /Mcf		

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[12] Aquifer Disposal of Carbon Dioxide, Hydrodynamic and Mineral Trapping - Proof of Concept, *Edited by B. Hitchon, Geoscience Publishing Ltd., Sherwood Park, Alta., 1996.*

[13] *Large Scale Carbon Dioxide Production from Coal-Fired Power Stations for Enhanced Oil Production: A New Economic Feasibility Study, P. Tontiwachwuthikul et al., JCPT, Nov. 1998, 37:11, pp. 48-55.*

[14] *Ibid.*

[15] *TransAlta, private communication, 1999.*

[16] A Feasible New Flue Gas CO2 Recovery Technology for Enhanced Oil Recovery, *Paper presented at 1998 SPE/DOE Improved Oil Recovery Symposium, Tulsa, Oklahoma, 19-22 April, 1998, by M.Iijima, Mitsubishi Heavy Industries.*

[17] *TransAlta, private communication, 1999.*

[18] *PanCanadian, private communication, 1999.*

The preceding Table 1 summarizes the key assumptions and results arising from the above studies. It is worth noting that the three economic studies (AOSTRA, Wong et al, and Edwards) all indicate economically viable CO_2 EOR schemes at CO_2 field supply prices (which include costs of capturing, treatment, and compression at the CO2 source, as well as pipelining), which are considered attainable in the near future (ranging from $20+ to 30+ per tonne). Only the AOSTRA study provided a more detailed 'cost curve', indicating how much CO_2 can be profitably sequestered by EOR at what supply price.

Notes to Table 1:

AOSTRA:

The economic analyses were based on both 'social' and 'normal business' approaches. Other parameters were level of oil production (as percentage of simulated results) and oil prices. Results shown are based on the 'normal business approach utilizing full flow through taxation', 75% oil production and a light crude oil price of $25/bbl.

Wong et al.:

The EOR calculation was based on ten parameters; the most important of which were CO_2 productivity and oil price. The affordable CO_2 prices shown are based on an average CO_2 utilization rate of 6 Mcf/bbl (as found in the AOSTRA study) and an oil price of $26/bbl, with all other parameters at their 'most likely' 50%-percentile value.

The CBM calculation was based on nine parameters, the most important of which were CO_2 productivity, natural gas price and development cost. Table 1 shows affordable CO_2 prices as a function of natural gas price, with all other parameters at their 50%-percentile values. The sequestration potential by ECBM is still very uncertain. For the purpose of the modelling, Wong suggested using 1/3 of the estimates by the National Energy Board, as follows: year 2010: 14 Mt/y; year 2015: 40 Mt/y; year 2020: 60 Mt/y.

Edwards

Rates of return were calculated as a function of oil price and royalty rates. An acceptable rate of return was achieved for oil prices of at least $23/bbl and a royalty rate of 10% or less. The net CO_2 utilization rate was 3.2 Mcf/bbl.

Using the information in Table 1. as a basis, the Table discussed potential combinations of capture and sequestration technologies/applications and costs for the purposes of modelling the potential economic benefits of research that reduces costs. Assumptions were as follows (costs in C$ per tonne):

- Base case (Aquifer disposal): Capture (existing technology): $30; Piping: $1 (within 100 km); Injection, $7; **Net Cost: $38**; Potential: unlimited.
- Base Case (EOR): Capture (existing technology): $30; Piping: $3; Credit for sale of CO_2 to EOR operators: $20: **Net Cost: $13**. Potential: 1.5 Mt/y.
- "Infinite Sinks" Scenario (Aquifer): Capture (new technology): $20; Piping: $1; Injection: $7; **Net Cost: $28**; Potential: unlimited
- "Limited Sinks" Scenario (EOR): Capture: (new technology): $20; Piping: $3; Credit for sale: $20; **Net Cost: $3**; Potential: 10 Mt/y.
- "Infinite Sinks" Scenario (ECBM): Capture: (new technology) $20; Piping: $3; Credit: $15 (based on ~$4/GJ natural gas price); **Net Cost: $8**; Potential: unlimited.

The possibility of \$20/tonne CO_2 capture technologies, and the productive use of CO_2 in the enhanced recovery of oil and methane would have a substantial effect on reducing the marginal cost of compliance with tight constraints on GHG emissions. Total costs would also go down, but the magnitude of the reduction tends to appear only at higher emission constraints. The effect on the least-cost resource mix that meets a carbon constraint would be significant: less hydro and gas (unless emissions from gas plants can also be sequestered inexpensively) and more coal. The economic potential is limited to Alberta and Saskatchewan.

Implementation

The recommendation of the Technology Table should form the basis of an R&D strategy for CO_2 capture and storage, building on Canadian strengths and priorities.

Agencies responsible

The federal Program for Energy Research and Development now is developing a condensing/cryogenic system for CO_2 purification and removal for eventual use in enhanced oil or gas recovery; this complements current work on CO_2/O_2 combustion. A second PERD project is to estimate the CO_2 storage capacity of Canadian coal seams that have suitable reservoir properties for the sequestration of CO_2; this complements the current pilot project on the sustainable development of coalbed methane.

Economic cost to the electricity sector

In assessing the economics on a project basis, it is necessary to take into account, and make explicit, assumptions about EOR and CBM producers' willingness to pay for CO_2. With many producers of CO_2 facing a positive cost to their CO_2 production in a GHG-constrained world, buyers of CO_2 would have a large selection of suppliers to choose from and could therefore bid the price down. Willingness to pay is also a function of the prices of oil and gas. For example, if emission caps increase the price of natural gas but decrease the price of oil, the value of CO_2 for CBM would go up and the value for EOR would go down.

It is difficult to estimate the economic benefits of improved research. The special geology of the Western Canadian Sedimentary Basin, in conjunction with heavy coal-dependence in Alberta and Saskatchewan may mean that geologic sequestering has a natural advantage and that research results can be applied there first.

Economic effects on other sectors

Improved capture technologies are primarily being considered for applications in the petroleum and electricity industries. However, if costs and minimum effective scale can be reduced, capture could also occur for other large point-source emitters. Proximity to suitable geologic storage is a key consideration as costs escalate rapidly if CO_2 has to be piped over large distances.

Regional effects

This measure affects emissions primarily in Alberta and Saskatchewan.

Experience in other countries[19]

In the U.S., as of mid-1998, about 60 million m^3/day of pure CO_2 is being injected at 67 commercial EOR projects, mostly in west Texas. Enhanced oil recovery from CO_2 flooding totals about 24,000 t/day (180,000 barrels/day). Assuming typical project CO_2/EOR ratios of about 6 Mcf injected (net) per barrel of oil recovered, an estimated 31 million m^3/day of CO_2 currently is being stored.

Since 1996, operator Burlington Resources has stored over 57 million cubic metres of CO_2 in Cretaceous Fruitland coal seams at their Allison Unit production pilot, located in the northern San Juan basin in the U.S. Based on current costs and performance, CO_2-ECBM may be profitable in the San Juan and nearby basins at prevailing wellhead natural gas prices of U.S.$0.06 to $0.07/m^3, representing an estimated 8.5 Gt of CO_2 storage potential.

Necessary conditions for implementation

CO_2 capture and storage research funding must compete with other promising development areas, such as fuel cells, biomass-renewable fuels and large-scale biological sequestration.

Areas for further research

- Extension and refinement of cost and volume data for enhanced oil recovery and coal-bed methane options;
- Research and development in pre-combustion capture technologies;
- Development of least-cost technology designs for different fuels and scale of plant.

Analysis; Table Views

Capture of CO_2 and its subsequent storage in geologic formations could have a large effect on the cost of emission reduction in Alberta and Saskatchewan. Alberta and Saskatchewan have both a large inventory of electricity-related emissions and storage in geologic formations. This measure is a regional option because geologic potential is limited outside the region and the cost of pipelining captured CO_2 over long distances is prohibitive. Potential benefits of the storage technology include productive use in extracting coal-bed methane and in enhanced oil recovery.

There is active research and some installations in Norway and the U.S. Capture and geologic storage is not limited to coal-fired facilities, although in power generation they would have the most to gain from its use, due to higher emissions per kWh.

The measure as brought forward suggests an objective of $20/tonne CO_2 for the capturing cost. However, there was also the view that this was unduly optimistic. The Phase II analysis suggests that availability of the technology at this price would reduce the total cost of compliance with a carbon constraint substantially (see Table 2)

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[19] *CO_2 Sequestration in Deep Coal Seams: Pilot Results and Worldwide Potential*, Paper presented at GHGT-4 in Interlaken, Switzerland, 30 August - 2 September 1998 by Scott H. Stevens, Vello A. Kuuskraa, Denis Spector, and Pierce Riemer, IEA Greenhouse Gas R&D Programme (http://www.ieagreen.org.uk/pwrghgt4.htm)

Table 2

Costs of Compliance

Level below 1990	Sink Type	Gross Cost ($ billion)	
		Estimate	NRCan base
94%	Limited	3.3	3.9
94%	Infinite	2.5	
80%	Limited	5.3	6.0
80%	Infinite	3.5	

In terms of resource mix, the Limited and Infinite Sinks scenarios showed carbon-constraint responses that had more coal than the Base scenario, as expected, along with less gas and less wind. They also had more hydro, except in the Infinite Sinks scenario in 2020 which had less hydro in the response at both 94%- and 80%-of 1990-level emission constraints.

Since R&D in this field is very active, there is a need, at a minimum, for ongoing review of technology development and refinement of cost and potential estimates. The measure would also focus on commercial demonstration. The industry would propose unconstrained access by all Canadian firms to technologies developed under research partnerships with government.

Conclusion: Strong support, subject to caveats. There are strong advocates as well as counter-balancing cautions about technological optimism. Some members think there may be greater economic potential than identified in the scenarios, while others feel the low-cost storage scenarios assumed in the modelling were much too optimistic; that an emissions reduction strategy should not rely on costs in the order assumed; and that carbon storage is an unproven technology: large-scale capture of emissions from coal-fired power plants at competitive costs remains to be demonstrated. Others want to have order-of-magnitude estimates of the cost of the research before expressing an opinion. (Full-scale demonstration of O_2/CO_2 recycling would likely cost on the order of $100 million). As with all R & D expenditure, strategic decisions must be made regarding duplicating other countries' efforts versus seizing the initiative, and regarding allocation of scarce funds among technology areas. Some members felt this measure should be implemented right away while others felt further consultation or analytical work was necessary to firm up costs and benefits.

Some Table members also stressed the need for further scientific and environmental impact assessment of this measure.

4B) Financial support for research, development and demonstration: fossil fuel technologies with potential to significantly reduce GHG emissions.

Background

Private sector, industrial co-financing can also play a role in R&D support of fuel technologies which have a potential to reduce GHG emissions. The level of private sector participation will depend how much emission reduction need occur.

Implementation

Existing government funding mechanisms and research infrastructure can be used to channel financial support for R&D measures.

Impact on other sectors

The development of fossil fuel technology options should be encouraged within the framework of fossil fuel technologies to reduce GHG emissions. Price competition among fossil fuel suppliers keeps a downward pressure on energy pricing and will provide economic benefits even in a carbon-constrained world.

Regional effects

Support for GHG-reducing fossil fuel research and development might help those regions which are dependent on fossil fuel use for electricity generation. The development of advanced CO_2 sequestration technologies and improved combustion and fuel use efficiencies could mitigate and possibly reverse the regional disadvantages created by carbon constraints. Integrating CO_2 storage technologies with large centralized and concentrated CO_2 sources, such as coal-fired power plants, may have a large impact in the electricity sector.

Economic cost to electricity sector

Support for research, development and demonstration of emerging fossil fuel technologies can lead to efficiency gains in the production and use of fossil fuels. Some of these gains may also offer GHG emission reductions and are therefore cost-effective. Technology efficiency gains are possible across all fossil fuels, including traditional conventional fuels such as oil, natural gas and coal, and other combustibles such as recycled hydrocarbons, petroleum cokes, other refinery products, unprocessed gas, orimulsion, etc.

R&D support provides an incentive to further improvement and development of fossil fuel technologies in electric power generation. Energy diversification considerations may still play a role in Canada's R&D objectives, however.

Economic effects on other sectors

The benefits of technologies that improve fossil fuel combustion are cross-sectoral. The industrial sector, which increasingly generates its own power, will also benefit from technology improvements. Building Integrated Gasification Combined-Cycle (IGCC) power plants, for example, will allow industry to derive its fuels from a number of sources and to use the electric power for base-load or peaking, petrochemical feedstock production, storage or use of CO_2, and/or heat production.

On a larger scale, the movement to meeting Kyoto commitments will increase the demand for natural gas since it is less GHG-intensive. However, if sufficient reserves of cheap natural gas are not available, the technology focus may have to turn towards coal. Canada has vast coal resources, which could be used even in a carbon-constrained world, if CO_2 storage technologies have been developed.

This measure will have to compete for research priorities against research options that may offer greater GHG reduction potential, whether inside or outside the electric power generation sector. Cost/benefit analysis is one method that can be used to rank research opportunities.

International trade implications

This measure will help ensure that the Canadian electric power generation sector stays abreast with the rapid improvements being made in fossil fuel use in electric power generation.

Analysis; Table Views

The Table generally supports the measure. Some members were concerned about the ability of Canada to do competitive work in these areas against the bigger research facilities in the U.S., EU and Japan. Others, recognizing the differences in scale of funding, wanted to make sure that at least the latest developments were tracked so that that Canada could find its appropriate niches. Other members did not want to see renewables left out of likely research options as a result of fossil fuel-related research. Environmental and social impacts should be considered when deciding on R&D for particular technologies. Support for this measure hinges on how it is financed.

5. Plan for Hydro

Address barriers to Hydropower

A) Federal and provincial governments to encourage development of the appropriate scientific criteria for the use of hydro resources in Canada and elsewhere (e.g. development agencies, Clean Development Mechanism, Commission for Environmental Cooperation)..

B) Federal and provincial governments to acknowledge hydro as a renewable and a low GHG-emitting source of electricity.

C) Federal and provincial governments would address other obstacles to environmentally and socially acceptable hydro in forming an ongoing part of the electricity sector's response to climate change (e.g. improvement in the relationships between developers of new hydro and directly affected communities, especially aboriginal communities, and further research into fish impacts and their mitigation.

Background

The Phase II analysis of the Electricity Table has indicated that expansion of hydropower is an important contributor to a least-cost solution to reducing GHG emissions in Canada. While 64% of electrical energy in Canada already comes from hydropower, there are still substantial additional resources available that may be economic, renewable and environmentally acceptable. This measure addresses a number of barriers to development of such hydropower. Other barriers are being addressed by other measures.

The measure addresses mainly the expansion of hydropower to meet Canadian demand. However, it also includes an international element because the most economic and environmentally effective portfolio to meet Canadian GHG reduction commitments may include Clean Development Mechanism (CDM) or Joint Implementation (JI) actions, including projects in developing countries and the export of hydropower to the U.S., displacing higher-emitting local production.

This measure, along with other related measures, could be instrumental in enabling a significant number of hydropower developments to proceed.

Implementation

Given that new hydro developments can have a lead-time of up to 10 years, the measure should be initiated now if new hydro is to contribute to GHG reductions as early as the Kyoto first budget period. Once initiated, only a modest degree of ongoing action would be required.

Agencies responsible

Federally, these include the Departments of Environment, Natural Resources, Fisheries and Oceans, International Trade, and Foreign Affairs. Provincially, they would include those departments responsible for environmental and consumer protection issues.

Economic cost to electricity sector

Possible cost savings

Economic effects on other sectors

Canadian hydro plant suppliers and constructors would benefit due to increased demand. The majority of the development expenditures would be for Canadian-made goods and services.

Regional effects

Quebec, Newfoundland, Manitoba and BC likely would experience the bulk of any expansion resulting from this measure, but other provinces may benefit as well. Local communities to new projects would experience job creation and attendant economic stimuli.

International trade implications

Potentially there could be a large increase in hydroelectricity trade with the U.S., as well as trade in GHG emission rights. Canadian suppliers could also enhance their experience and competitive position internationally.

Necessary conditions for implementation

The following conditions are required:

- coordination between federal government departments in order to deal with issues on an integrated and comprehensive basis
- harmonization between federal and provincial government requirements
- negotiation of appropriate criteria with other countries and agencies
- involvement of industry and NGO stakeholders
- rapid clarification of the roles and relationships of First Nations communities
- research on the environmental impacts of hydro projects and their mitigation

Analysis; Table Views

Model results illustrate the role of hydro development in emission reductions. Furthermore, under Base Case assumptions with the no reduction scenario, 41 TWh of additional hydro, from 1995 generation is projected to be installed by 2010. Not addressing barriers to hydro could jeopardize these projects and significantly increase GHGs in the base case. If there were no new hydro, unconstrained emissions in 2010 would be 5 Mt higher than in the Base Case.

Under the Base Case assumption, 3 TWh of additional hydro is required in 2010 in order to meet a carbon constraint of 94 percent of 1990-levels. This amount increases to 25 TWh in 2020.

The amount of hydro built to meet the constraint in a least-cost fashion increases if higher demand growth and/or higher gas prices are assumed or if Bruce A is not returned to service.

The effect on the cost of meeting a carbon constraint of a hypothetical elimination of new large hydro investment is illustrated in Table 3 by assuming no new hydro is allowed in both carbon-unconstrained and carbon-constrained cases. Costs of supply are higher in both cases than if new large hydro is permitted to occur, but the cost of stabilization at 94% of 1990 emissions is $5.9 billion over 30 years if no new large hydro is permitted, compared to $4.2 billion assuming new hydro is available.

Table 3

Impact of No New Hydro

Scenario	Unconstrained Emissions in 2010 (Mt)	Cost of Stabilization at 94% of 1990 emissions (NPV - $ billion)	Marginal Abatement Cost in 2010 ($/tonne of CO2 equivalent)
Base Case	118	3.9	12.19
No New Hydro	123	5.9	14.34

Table members strongly support this measure, recognizing that there is a need to ensure, through public processes, that any hydropower developments are environmentally and socially acceptable.

The Table acknowledges the scientific/technical basis for recognizing hydro as renewable. It also recognizes that environmental and social acceptability of hydroelectric developments is specific to the site and the design of the project. The Table is using the term 'renewable' to refer to the replenishment of supply by natural cycles. The Table recognizes that 'renewable' is not synonymous with the broader concepts of green power and sustainability, which it did not address. Some Table members caution that there is a need to examine the impact of climate change on hydro capacity in the future. Other members believe that any impact could be positive as well as negative.

6. Plan for Nuclear

Clarify Nuclear Policy and Resolve Regulatory Issues as Required

A) Governments to clarify whether there is a place for nuclear power in Canada's future electricity supply industry, in particular, with regards to climate change.

B) If so, then there is a need for governments to resolve regulatory issues regarding nuclear power in forming an ongoing part of the electricity sector's response to climate change.

Background

Nuclear power is a large source of non-greenhouse gas emitting electricity. It represents about 17% of Canadian electricity production and, historically, over 60% of Ontario's generation mix. Other Canadian reactors are in New Brunswick and Quebec. Approximately 5,000 megawatts of nuclear capacity is currently laid up in Ontario in order to concentrate all available resources on improving performance at the 12 newer nuclear units. The long-term plans for Canada's nuclear fleet will affect national strategies for achieving Kyoto targets. The cumulative effects of the current regulatory regime are considered a disincentive by the industry, particularly in the development of public-private investment partnerships.

Should governments decide there is a place for nuclear, new nuclear capacity could play a role in the shift of the generation mix to reduce greenhouse gas emissions. To do this, the regulatory regime for nuclear projects needs to be streamlined for efficiency, without eroding its effectiveness. Regulatory process streamlining provides lower costs during the construction phase and makes the investment decision easier. A shorter regulatory process would reduce investor risk. Similarly, regulatory streamlining may be needed to encourage public-private investment partnerships needed to maintain existing nuclear capacity in a restructured or privatized Ontario electricity sector.

It is within this context that the federal and key provincial governments need to provide a clear policy signal on the continued and new use of nuclear power in Canada. The federal government could then work with interested stakeholders in making the regulatory regime both effective and conducive to continued nuclear investments.

Implementation

This measure could be initiated immediately. The decisions to return the Pickering "A" and Bruce "A" plants to service in Ontario will be made within the next five years. For new facilities, there is a ten to fifteen-year lead-time from project initiation to first power.

Agencies responsible

The Atomic Energy Control Board is responsible under the *Canadian Nuclear Safety Act* for licensing and regulating nuclear activities in Canada including the nuclear power plants. Provincial governments have pressure vessel, environment (along with the federal environmental role), and electricity regulation responsibilities.

Economic cost to the electricity sector

No cost, or possible cost reductions from implementation of more efficient regulation.

Economic effects on other sectors

The CANDU reactor employed by Canadian utilities is a technology that is both developed and based in Canada. New CANDU reactors, whether for the domestic or export markets, provide significant employment benefits in Canada

Regional effects

Nuclear power is currently concentrated in Ontario, with single plants in Quebec and New Brunswick.

International trade implications

Currently, CANDU reactors represent 5% of the installed world nuclear capacity and account for 15% of reactors under construction. There are significant opportunities internationally for the continued export of CANDU technology.

Experience in other countries

Japan, France and UK are relying on nuclear power as a principal strategy for their compliance with their Kyoto targets, with the United Kingdom projecting a 20 to 30% increase in nuclear generation. Other countries, including Korea and China, have active nuclear programs. In the United States, there is a trend towards extending the lifespan of existing reactors.

Necessary conditions for implementation

In order to realize a sustained nuclear future, there are issues that the nuclear industry must resolve, in co-operation with other stakeholders and government agencies. These include:

- A safe, socially- and environmentally acceptable, economic solution to the issue of the long-term management of nuclear waste, based on meaningful public consultations.
- Financial issues around the segregated fund for nuclear waste disposal and decommissioning
- Clarification of the environmental aspects (particularly the application of the Canadian Environmental Assessment Act) around the Nuclear Safety Act
- Consideration of longer-term operating licenses with appropriate checks and balances
- Re-examination of the Nuclear Liability Act in light of the restructuring of the electricity industry.

Analysis

Decisions regarding existing nuclear plants have a large impact on costs of meeting a carbon-constraint. The "No Bruce A Scenario" discussed in the modelling results illustrates the ripple effects across Canada of approximately 3000 MW of non-emitting capacity being eliminated from the national electricity supply, and the significant effects it would have on the cost of greenhouse gas reductions. The analysis suggests (see Table 4) that if Bruce A fails to return to service, the unconstrained emissions would be 8 Mt higher than in NRCan's base case in 2010. The marginal abatement cost of meeting a target of reducing CO_2 emissions by 94% of 1990 levels would rise from \$12.19/tonne CO_2 in the base case to \$15.33tonne CO_2 in the "No Bruce A" case. The cost of stabilization at 94% of 1990 emissions is \$5.0 billion in the "No Bruce A" case, compared to \$3.9 billion in the base case.

Table 4

Impact of No Bruce A

Scenario	Unconstrained Emissions in 2010 (Mt)	Cost of Stabilization at 94% of 1990 emissions (NPV - $ billion)	Marginal Abatement Cost in 2010 ($/tonne of CO2 equivalent)
Base Case	118	3.9	12.19
No Bruce A	126	5.0	15.33

There could be a role for new nuclear generation in meeting a binding emission constraint. Investment in new nuclear (not refurbishment) induced by emission constraints takes place in the Composite Scenario as follows:

- 33 TWh in 2020 under conditions of a constraint of 94% of-1990; and
- 7 TWh in 2010 and 50 TWh in 2020 with a constraint of 80%-of-1990.

Table Views

The debate over the continued and new use of nuclear power evokes a strong polarization of views from Table members. Both supporters and detractors are able to mobilize their views and perspectives around public safety, long-term waste disposal and economics of the option.

Table members agree on the need for federal and key provincial governments to clarify nuclear's role in Canada's climate change strategy. However, they were sharply divided on the merits of nuclear power as an acceptable response to climate change. There is agreement that nuclear power does warrant the continued attention of the policy makers given the prominence that it plays in Canada's electricity supply mix. Members supportive of nuclear power state that there is a need for a clear signal from government for private investors in the restructured electricity industry. They believe that there is unnecessary regulatory risk in the current approach for existing plants. They claim that opportunities exist to shorten the lead-time through public awareness and streamlining the regulatory process. They see nuclear power as a substantial part of the solution to climate change mitigation. Loss of this option would, in their view, raise the cost of compliance with a binding emissions constraint. As well, a successful nuclear industry in Canada would result in substantial export opportunities.

Some Table members do not support nuclear power as a solution to climate change. Other members assert that safety, the long term storage of wastes and other issues need to be addressed before nuclear power is considered. They stress that changes in the review process should not lead to inadequate environmental protection and emphasize the importance of public consultation on nuclear issues. Further, some members expressed concern about the risks associated with the transfer of nuclear technology to other countries.

7. Plan for Emerging, Non-GHG-emitting Technologies

The technologies considered by the Table for this measure are:

- Micro-turbines run on renewable resources
- Extra-low-head hydroelectricity
- Wind
- Solar
- Geothermal
- Biomass

The term "emerging, non-GHG-emitting" is understood to apply to technologies that are:

- proven in commercial operation (somewhere)
- expected to show substantial unit cost reductions when production volumes increase
- non-GHG-emitting, for all practical purposes

The plan is designed to ensure the availability of emerging, non-GHG-emitting technologies by the commitment period. In order to do so, costs of deployment of these technologies, particularly wind, need to be reduced. The plan would do so by providing experience in building and operating larger facilities, as well as through increased economies of scale on the part of Canadian equipment manufacturers. The Québec Régie de l'Énergie has estimated that in order to bring a viable Canadian industry into being, a minimum of 50 MW of wind energy capacity must be constructed each year for nine years. The intent of this measure is not to use government money to buy small reductions from today's least expensive source, but to support promising climate-friendly technologies in the expectation that their total costs will be substantially reduced when the financial support is removed. In turn, this could reduce the total cost of compliance with a Kyoto-like policy below that of the best-modelled result since the technology cost reduction is not reflected in the estimates.

In order to achieve this aim, a plausible business plan leading to cost reductions over a 5- to 10-year period needs to be developed, so that these technologies could compete with other generation in a carbon-constrained world. A conceptual discussion of such a business plan by the Table was based on government support of roughly $500 million (present value over 20-30 years at a 7 percent discount rate). Any support measure would contain a "sunset" clause that would decrease the level of support as the industry matured. Analysis done by the Table does not make any assumptions with regards to whether the measure would be financed by the ratepayer or the taxpayer.

Recognizing the regional variability of these energy sources and of the electricity market, the Table considered a "tool-box" of measures that could be utilized as appropriate in each province. The cost to governments of the "tool-box" would be roughly $500 million.

The package was modelled as a 1-2.5¢/kWh production credit; *i.e.*, financial support for the package was taken as being equivalent to 1-2.5¢/kWh of electricity produced by the targeted technologies. For modelling purposes, the Table assumed a 1 or 2.5 cent credit over ten years for investments made during 2000 to 2005, ramped down to a half cent or 1.25 cent credit for investments made to 2010, and then no credit for investments made after 2010, when a commitment period measure would presumably be in place. The effect, in addition to the desired impact of ensuring the availability of these technologies in the commitment period, is an emission reduction of 2-3 Mt/yr. by 2010. The marginal cost of abatement for these assumed credits ranged between $7 and $14/tonne of CO_2 equivalent.

Table members strongly support this basket of options, as a preparatory measure, at the funding levels examined. Support is, however, contingent on the degree of confidence that the plan will produce real cost reductions. The program must contain sunset clauses and ramp-down features, be production-based rather than investment-based, include domestic manufacturing capability development and have defensible baseline technology cost projections. Some Table members caution that there is a need to examine the impact of climate change on emerging technology resource capacity in the future. Other members believe that any impact could be positive as well as negative

7A) Government procurement of electricity from emerging non-GHG emitting sources.

Federal, provincial and municipal governments (where appropriate) to expand purchases of non-GHG/low emitting sources of supply.

Background

In January 1996, the Minister of Natural Resources announced federal government plans to purchase 'green power' from utilities, to encourage the development of renewable energy sources. To qualify, the power must be generated from new or newly expanded renewable energy facilities and certifiable under EcoLogo ™, Environment Canada's Environment Choice program.

In September 1996, Ontario Hydro undertook a pilot green power marketing initiative and approached NRCan and Environment Canada to assess their interest in purchasing green power. In November 1996, the two federal departments agreed to purchase 12.5 GWh of green power for their facilities in Ontario at an annual premium cost of $500K per year. In return, they were offered annual emission reduction credits for CO_2, SO_2, NO_x and particulates. In 1997, Ontario Hydro decided not to proceed with the power purchase agreement. The arrangement is on hold pending the opening of the Ontario electricity market to retail competition in 2001.

In 1997, NRCan and Environment Canada stepped up their commitment to green power by pledging to purchase between 15 to 20 percent of their electrical energy needs in the form of green power by the year 2010. In the same year, the two departments agreed to purchase a total of 12.2 GWh of green power every year for 10 years from ENMAX, Calgary's electric distribution company. That will reduce GHG emissions from their Alberta facilities by about 11,000 tonnes per year.

Agencies responsible

Procurement agencies of federal, provincial and municipal governments.

Policy linkages to other sectors

The purchases would signal governments' leadership role in enhanced voluntary action.

Economic cost to the electricity sector

There may be some indirect costs to utilities resulting from higher administrative requirements of managing green power contracts.

Economic effects on other sectors

Establishment of new emerging non-GHG emitting technology installations would benefit local communities.

Regional effects

Federal and provincial governments would generally wish to achieve their green power purchasing targets using the lowest-cost renewable energy sources. Provinces with the lowest renewable energy technology development costs and most favourably located renewable energy resources would benefit most from this plan. The types of power acquired would likely vary from province to province.

E-MARKAL model runs generally show wind as the least-cost emerging non-GHG emitting technology, although some provinces also have competitive small hydro in the model. However, potential configurations and costs are sufficiently site-specific that a more finegrained analysis than is available through MARKAL would be required to determine the least-cost technology in a given locality.

International trade implications

While the measure may be insufficient to support development of a wind power plant manufacturing industry in Canada, it could make it economical for certain components to be manufactured domestically, in particular blades and towers. This could bring the Canadian content up to 70% of capital costs.

Experience in other countries

U.S.

In the U.S., the Department of Energy's Federal Energy Management Program (FEMP) helps federal agencies take advantage of the benefits offered by renewable technologies by developing showcase projects with a renewable energy feature. To date, these include:

- Installation of more than 2 megawatts (MW) of photovoltaic (PV)-generated capacity for the U.S. Department of Defence. Another 1.6 MW of PV are currently being procured or are in the construction stage.
- Installation, by the National Park Service (NPS), of more than 455 PV systems, 36 solar water heaters, and many other energy conservation measures.

Necessary conditions for implementation

- long-term commitment to green power purchasing contracts by governments;
- Land use, environmental and building code policies at local or regional levels may need to be revised to accommodate renewable energy development.

Analysis; Table Views

Government green-power procurement means a contractual commitment to buy electricity from suppliers of electricity generated by emerging non-GHG-emitting technologies. These contracts will entail higher cost to the government than conventional purchases at market or regulated rates. Some Table members see government procurement as a leadership issue, as well as a financial incentive. The Table modelled a program that spends 10 times the current government "green power" procurement budget for 5 years and 20 times the current budget for subsequent years, at a 2-cents/kWh premium. Since current government green-power expenditures are approximately $400K/year, this means an assumed annual budget of $4M in 2000 –2005 and $8M thereafter. The 2-cent premium was treated as a 2-cent-per-kwh reduction in the cost of production for all emerging non-GHG-producing technologies. The model results suggested that no incremental investments would take place under these conditions, since the model was already showing greater volumes of GHG-free electricity from emerging technologies in a least-cost business-as-usual solution

The Table does not take from this that procurement is not cost-effective in general. Cost reductions for proven technologies may depend on the establishment of a domestic power industry and the $4-8 million assumed in the model would provide for about 25 MW per year of wind power plant construction, about half of what the Régie de l'Énergie estimates is required for a viable domestic industry.

(7B) Installation on government buildings of site-based generation using emerging non-GHG-emitting technologies.

Federal, provincial and municipal governments (where appropriate) to install emerging non-GHG-emitting sources of self-generation on-site for government buildings.

Background

In January 1996, the Minister of Natural Resources announced plans to purchase electricity from emerging, non-GHG-emitting electricity generation technologies. Potentially, some of the electricity could come from on-site generation at government buildings.

In April 1998, the federal government earmarked $12 million for the Renewable Energy Deployment Initiative (REDI), a three-year programme to encourage the use of renewable energy systems for space and water heating. A component of REDI is REDI for Federal Facilities, which provides a 25% contribution for purchase and installation costs, up to a maximum of $50,000 per project. Eligible systems include high-efficiency and low-emission biomass combustion systems greater than 75kW. Such facilities could be located on a government building site.

Implementation

There are no timing impediments to installations of on-site emerging, non-GHG emitting electricity generators. Such installations could be part of a portfolio of supply sources developed to achieve 15 to 20 percent penetration of green power into federal government energy purchases by the year 2010.

Economic cost to the electricity sector

Cost of lost electricity sales to government facilities.

Economic effects on other sectors

This measure would benefit manufacturers of the requisite equipment, as well as installers

Experience in other countries

U.S.

In 1997, U.S. Federal government made a commitment to place 20,000 solar energy systems on Federal buildings as part of the Million Solar Roofs Initiative. That initiative aims to install a total of 1 million solar energy systems on residential, commercial, and public-sector buildings by the year 2010. The use of photovoltaics for electricity generation will be one of the main focuses of the initiative.

Necessary conditions for implementation

Facilities capable of incorporating the generating equipment. Building codes may also need to be modified.

Analysis; Table Views

This measure is a variant of procurement. Installations on government buildings would enhance communication of government's leadership. It was pointed out, however, that the most cost-effective eligible installations are now off-grid, and that most government facilities are grid-connected.

The expected GHG impact is very limited. Based on electricity consumption at federal facilities, potential CO_2 emission reductions could be approximately 15 kt per year. Its value lies mainly in demonstrating leadership and commitment.

7C) Production credits

Provide credits to producers based on energy output from emerging, non-GHG-emitting technologies.

Background

There are two main ways to provide credits. A *production credit* is a payment to the producer that is proportional to output – a cents-per-kWh incentive, paid on an as-produced basis. An *investment credit* is proportional to capacity or capital cost, paid all at once, or on a fixed schedule. Credits would allow the emerging non-GHG-emitting power developer to lower the cost of production to the market price. Benefits include relatively low administrative cost, direct financial assistance to emerging technologies with external benefits, and an incentive towards operating efficiency. Production credits could be paid directly to the producer, or through the tax system. In the latter case, the amount of available credits may be limited by the extent of the owner's tax position

For the purposes of modelling, the following assumptions were used:

- The capital equivalent of a reduction in variable cost of production of 1 cent or 2.5 cents over ten years, for investments made in 2000.
- The same in 2005.
- Half the amounts for investments in 2010.
- Nothing after 2010.

The modelling did not constrain the amount of money available – the exercise was designed to estimate how much would be required if the full economic potential of reduced-production-cost emerging non-GHG-emitting technologies were developed.

Policy linkages to other sectors

The credit could be viewed as setting a precedent for similar incentives available to other GHG-intensive industrial sectors with emerging technologies that reduce emissions.

Economic cost to the electricity sector

Reduced costs.

Economic effects on other sectors

Emerging non-GHG-emitting technology installations would benefit those localities with good renewable energy resources and low costs of any land required. Local tax revenue and some modest employment effects may be expected.

Regional effects

Provinces with the lowest renewable energy technology development costs and favourable renewable energy resources would benefit most from this plan. The types of power acquired would likely vary from province to province.

Experience in other countries

Certain non-GHG-emitting technologies receive tax subsidies in the U.S. Portugal also provides significant tax credits. Canada, France, Germany, the Netherlands, Norway and Switzerland rely on tax depreciation to channel incentives for investment in electricity from renewable sources.

Direct payments to developers of wind-generated electricity are used in Denmark. Britain provides above-market contracts for renewable energy generators in certain classes and cost ranges, though it is funded through a levy on electricity use. In Germany, Greece, Portugal, and Spain, independent generators of electricity from renewable energy technologies are guaranteed preferential sales contracts from national or regional utilities.

Areas for further research

The effectiveness of a production credit, as a means of reducing emissions, is likely to vary from technology to technology, depending on the state of commercialization. The appropriate level of incentive and its "decay" over time would need to be carefully estimated to avoid providing too much of a windfall or, alternatively, unacceptably low uptake.

Analysis; Table Views

The Table felt that production credits should:

- apply to new capacity only
- decrease over time
- apply only to facilities that are capable of producing through to 2012

The MARKAL model was run twice, at production credits of 1 cent and 2.5 cents per kWh respectively, to estimate the market penetration without a budget constraint. The 1-cent credit reduced emissions (relative to the carbon-unconstrained case) by 1.2 MT CO_2 in 2010, while the 2.5-cent credit reduced emissions by 2.3 MT in that year.

A 1.2 MT reduction is about 5 percent of what is needed to reduce emissions in 2010 to 94% of 1990 levels. For the one-cent credit, the model moved about 4700 GWh out of large hydro (45%) and gas (55%) and put it into emerging, non-emitting technologies.

A 2.3 MT reduction is about 8 percent of a 94% of 1990 reduction target for the sector. The 2.5-cent credit moved about 6500 GWh – 1% of Canadian production -- from gas, large hydro and coal (in proportions of 61/29/10) into emerging, non-emitting technologies - mainly wind.

Depending on the level of financial support, a net benefit to the industry of $150 – 560 million was more than offset by government expenditures of $257 – 877 million, for net total costs (relative to a no-reduction case) of $107 – 317 million. These costs are all in present value to 2030. Annual costs would be on the order of 5 – 10% of these amounts, depending on the year. Marginal abatement costs range between $7/tonne for the 1-cent credit and $14/tonne for the 2.5-cent credit. These estimates do not reflect any cost reductions in emerging technologies, which is its specific intent.

The modelled costs are relative to the unrestricted emissions case and not relative to the least-cost way of achieving the emission reductions. It is likely that the least-cost way of achieving either small reduction in the model would be by substituting gas, and some hydro for coal.[20]

This does not mean the production credit is not economically efficient. However, it does illustrate the preparatory nature of the measure: the intent is not to use government money to buy small reductions from today's least expensive source, but to support promising climate-friendly technologies in the expectation that their total costs will be substantially reduced when the financial support is removed. In turn, this could reduce the total cost of compliance with a Kyoto-like policy below the best-modelled result, since, as indicated above, the technology cost reduction is not reflected in the estimates.

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[20] *No model runs showing the least-total-cost way of achieving 1.2 or 2.3 MT of reductions in 2010 was done.*

7D) Rebate on retail bill premiums paid for climate-friendly electricity from emerging technologies.

Government to rebate a portion of above-market amounts paid on retail bills by customers electing to buy electricity produced by emerging non-GHG-emitting technologies.

Background

This measure aims to stimulate the market for emerging non-GHG-emitting technologies. In jurisdictions with retail access, consumers can enter directly into contracts with suppliers for the purchase of climate-friendly power at above-market rates. In monopoly jurisdictions, a special rate or tariff may be developed, in which the utility resells the climate-friendly power. Customers may then voluntarily adopt the higher tariff. A cap on either total support payments or on the number of subscribers may be required, however, in order to limit government expenditures

Canadian experience with optional low-environmental-impact-related prices or rates includes one ongoing programme using wind power in Alberta. In 1997, ENMAX, formerly the City of Calgary Electric System, announced that it would purchase over 3 million kWh of wind energy. Federal facilities have also made similar commitments (see Measure 7A).

Implementation

Potential Canadian demand for such a measure may be partly estimated by actual uptake figures for other, similar programmes. Table 5 on the next page provides a sample of price premiums and participation levels of green power marketing programmes in the U.S. Actual uptake rates are substantially lower than surveyed willingness to pay. However, larger uptake could be expected if customers subsequently receive a partial rebate of the premium.

Agencies responsible

In provinces without retail access, regulation would be required to mandate or encourage utilities to offer above-market green power rates. Source disclosure and/or "environmental content" certification would also be required to provide consumer confidence and protect against fraud.

Table 5

Price premiums and Participation Levels for Green Power Marketing Programmes[21]

UTILITY	PRICE PREMIUM ($U.S./month)	PARTICIPATION
Public Service Co. of Colorado	1.73	1.4% (a)
Wisconsin Public Service	1.85 (b)	9.0% (b)
Gainesville Regional Utilities	3.27	1.0% (c)
Sacramento Municipal Utilities District (SMUD)	6.00	29.0% (d)
Niagara Mohawk	6.00	0.6% (e)
Detroit Edison	6.59	0.3 (f)
Traverse City P & L	7.58	3.1% (c)

Notes:
(a) Of all residential customers.
(b) Based on market simulation; actual price premium is $1.71 but participation not yet known.
(c) Of all customers.
(d) Based on telemarketing effort.
(e) Based on one targeted mailing.
(f) Based on non-targeted mailings

Economic cost to the electricity sector

Based on experiences in other jurisdictions, the cost of reprogramming billing systems could be on the order of $50,000 to $100,000.

Experience in other countries

More than 30 U.S. utilities have either developed or have announced intentions to develop green pricing programs for their customers. Actual or proposed price premiums for energy-based green pricing offerings generally range from U.S. 2.0¢/kilowatt-hour (kWh) to U.S. 3.0¢/kWh, but can be as low as U.S. 0.5 ¢/kWh and as high as U.S. 6.0¢/kWh. New renewable energy capacity developed under green pricing programs is expected to reach more than 20 MW during 1998 and more than 35 MW by the end of 1999.[22]

The majority of green pricing options has been offered to residential and small commercial customers. Only a few utilities are attempting to target wholesale or industrial customers. Most of the programmes are employing wind and photovoltaic energy systems in centralized commercially operated facilities. Only a few programmes are using grid-connected renewables based on customers' premises.

Take-up of the programmes has generally lagged behind predictions. In most cases this has been attributed to some of the following factors: (1) customers' propensity to overstate their likelihood to participate in the programmes, (2) the relative newness of the programmes themselves, and (3) the fact that many of the programmes have not been marketed aggressively.

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[21] *Source: Weijo, R.O. and D. Boleyn. 1996, "Product Concept and Field Test of Green Marketing Programs," American Council for an Energy-Efficient Economy 1996 Summer Study; http://www.eren.doe.gov/greenpower/aceee2.html*

[22] Information Brief on Green Power Marketing, *3rd Edition, by Blair Swezey & Ashley Houston, National Renewable Energy Laboratory, September 1998*

Other countries that have premium tariffs for 'green power' purchases include Denmark and the Netherlands.

Necessary conditions for implementation

- It is critical that existing generation not be certified as qualifying, since the extra charges to customers would produce a windfall without reducing emissions.
- Monopoly generation utilities would have to agree to offer emerging non-GHG-emitting power purchases to consumers and either accept non-utility generation or build their own plant.
- The applicability of this measure would vary depending on the structure of the electricity industry in each province.
- Similarly, in provinces without retail access, utilities would have to agree to promote, or at least make customers aware of the option, and implement the necessary billing changes.

Analysis; Table Views

This measure provides partial rebate of above-market amounts voluntarily spent by consumers on climate-friendly electricity from emerging technologies. The measure is understood to apply most effectively in provinces with retail access, although regulated rate options based on contracts with owners of specific types of plants are also possible.

So-called "green power" customers are the relatively small percentage who are willing to pay higher prices to help reduce environmental impacts. This voluntary contribution to the public good can be strengthened by offering rebates on the extra amounts paid. The rebate would induce additional customers - whose willingness to pay at current prices is not high enough - to sign up.

The measure is distinct from the producer credit in that it enhances voluntary action by customers, rather than reducing production costs. The benefit to producers would occur as an increase in market share. Program effectiveness could be reduced by the free rider effect, since all those willing to pay the full premium without the rebate would be receiving it. A careful consumer market assessment, that takes into account the discrepancy between stated and actual willingness to pay, would therefore be required.

Source disclosure or 'environmental content' certification would be required to provide consumer confidence and protect against fraud.

An upper cap on total subsidy payments or on the number of subscribed consumers may be required to limit government expenditure.

The Table was divided on the potential of this measure. Some environmentalists on the Table were strongly in favour of it.

7E) Generation quotas or portfolio standard (small percentage)

Governments to establish mandatory quotas or portfolio standards to achieve targets for emerging non-GHG-emitting sources of supply as a minimum share of the average generation mix.

> **Note: this measure refers to a small quota or portfolio standard considered necessary to stimulate the market for emerging, non-GHG-producing technologies. A larger portfolio standard, aimed at achieving a significant portion of a Kyoto-like target, is discussed in Section V.**

Background

Quotas refer to fixed amounts of specific technologies. A portfolio standard requires all sellers or generators of electricity to ensure that a portion of their electricity sales is met by approved technologies. A portfolio standard can lead to competitive supply of those technologies covered within the standard and need not favour any generation technology except insofar as it meets the criteria for the portfolio. The mix of technologies assumed for the Table's purposes is one possible set of eligible technologies. Wind, solar, geothermal and biomass options are usually part of most "Renewable Portfolio Standard" (RPS) programmes, which is the terminology in common use.

In Ontario, the committee responsible for making recommendations on the design of a restructured electricity market considered renewable portfolio standards in the context of other potential pollution control measures. The Committee was evenly split on the issue of RPS, which largely reflected uncertainty as to whether there would be caps on emissions, especially GHG emissions. RPS supporters viewed the instrument as complementary to caps, and as "insurance" against a potential absence of commitment on a GHG cap. Those opposed felt comfortable that caps on emissions would afford adequate protection, based in part on the Minister of Environment's assurance that Ontario Hydro's voluntary commitment on GHG would remain in place. The addition of a RPS would then be redundant.

Implementation

Due the lead times required for development of the plants required, the quotas or portfolio standards would be need to be announced well in advance.

Staged implementation would allow expansion of the appropriate industries to proceed at a manageable pace, which tends to ensure that constrained supply does not increase prices unnecessarily.

A quota or portfolio standard program could contain a sunset clause, with phase-out of the program once emerging non-GHG emitting technologies become competitive with conventional energy sources.

Agencies responsible

Provincial regulators of electricity would be responsible for imposing quotas or portfolio standards on electricity sellers or generators. The exact mechanism of a standard would depend on market structure.

Policy linkages to other sectors

Industries that self-generate power (*e.g.* cogeneration) may be required to abide by portfolio requirements, especially if they sell excess power to the grid or to a third party.

Economic cost to the electricity sector

Both producers and consumers of electricity would absorb the administrative costs of complying with a portfolio standard. When producers pass the higher cost of electricity generation onto consumers, higher electricity prices may be expected to spur investments in energy efficiency and conversion to non-electric sources of energy.

Economic effects on other sectors

If electricity prices rose high enough as a result of the RPS, it could spur investments in energy efficiency and cause conversions to non-electric sources of energy, mostly natural gas. However, the larger penetration of renewables would at least partially counter-balance any upward effect on gas prices: there may be more gas used in direct heating and cooling, for example, but the amount of gas used in power generation would be lower.

Regional effects

Those regions with substantial new qualifying energy resources would be the primary beneficiaries of a national portfolio program.

Some provinces might wish to promote the development of specific energy sources via quotas within their own region. However, greater liberalization of electricity markets could put pressure on restrictive practices that are beyond specification of eligible technologies and the overall minimum percentage of supply obtained from them.

Experience in other countries

Several U.S. states including Arizona, Nevada, Massachusetts, Connecticut, Maine and Vermont have already implemented programmes. Other states such as California, Rhode Island, New York, Wisconsin and Illinois are approaching renewable energy development and deployment through the collection of Systems Benefit Charges (SBC). Some, such as Massachusetts are using both, by splitting off market development to the RPS and ensuring continued research through the SBC.

At the federal level, U.S. President Clinton's Comprehensive Electricity Competition Plan recommends a minimum 7.5% non-hydroelectric, non-imported renewable tradable portfolio standard by year 2010. In recent years, both the Administration and individual members of the U.S.Congress have introduced several RPS proposals. Each bill proposes different targets spanning different time periods and with different eligibility criteria. The bills specify that a minimum percentage of U.S. electricity generation or sales be obtained from renewable energy sources, whose definition may vary. This percentage ranged from 4 percent in 2010 under an earlier bill by Rep. Schaefer to 20 percent in 2020 under the Senator Jeffords' bill, representing an increase in renewable energy use ranging from 10 percent to more than five times the projected business-as-usual levels. One feature common to all proposals at the federal level is the proposal to create a national renewable energy credit trading market to implement the RPS.

Necessary conditions for implementation

- Determining the level of the standard
- Determining eligible resources and technologies
- Province by province portfolio standards may need to be harmonized

Analysis; Table Views

A quota or generation portfolio standard requires a minimum market share for a specified technology or group of technologies. The share may be specified in terms of energy or capacity. Specification of capacity share at any given percentage results in lower emission reduction than specification of the same energy share, since emerging non-GHG-emitting technologies tend to have low capacity factors.

In Section 5, the Table reports model results of a generation portfolio standard that requires 3 – 5% of total energy from emerging non-GHG-emitting technology, and achieves a 10 MT emission reduction in 2010. Such a standard is shown to be, according to the model, substantially more expensive than emission pricing that results in greater emission reductions. As indicated above, however the model does not take into account the technology cost reductions that are the driver for this measure. A smaller standard, perhaps tailored to the resource bases of the different provinces, and co-ordinated so as to share the burden regionally, would be useful as part of the transition. This is because such a standard could induce (emerging non-GHG-emitting) technology cost reductions in greater proportion to the resulting emission reductions than straight carbon pricing that builds mostly gas and large hydro.

However, many Table members were reluctant to support the measure. Some saw it as unnecessarily prescriptive. Some members felt that the standard is useful only in regulated jurisdictions. And of course the industry and its customers bear all the costs. The measure is also disliked in provinces seeking export markets for large hydro because developing U.S. Renewable Portfolio Standard (RPS) regulations may exclude large hydro as a qualifying resource. It should be noted, however, that some environmentalists on the Table were strongly in favour of the measure.

7F) Net metering for non/low-emitting sources, small systems

Provincial legislation requiring distributors of electricity within their jurisdiction to offer a net metering tariff to customers.

Background

The concept of net-metering is to credit utility customers for electricity delivered to the grid whenever their on-site generation facilities provide a surplus. Without net-metering, utilities usually install a second meter to measure any electricity that flows back to the utility grid. The electricity is then purchased under a net purchase and sale agreement at the 'avoided cost' rate, which is typically lower than the retail price (with differentials as high as 10 cents U.S. per kilowatt-hour). For small facilities, it is often not worth installing a separate revenue-quality meter: any differences in the costs or values of site-based power versus grid supply do not justify the expense.

Net-metering is especially useful for intermittent renewable energy technologies because it allows all or a substantially bigger portion of the customer-generated electricity to receive the retail price. This increases the economic value of small renewable energy technologies for customers. It also affords customers more flexibility in self-generation since they do not have to alter their consumption or install energy storage devices to maximize the value of their generation. The generating facility may be sized to match long-term energy consumption. Without net-metering, customers with net purchase and sale agreements are more likely to install smaller generators so as not to exceed their instantaneous power demand. As a policy option, thereby, net-metering provides economic incentives to encourage further expansion of renewable energy technologies without public funding.

Implementation

If a net-metering arrangement were expected to bring about substantial uptake, a lag period of one or possibly two years may be required for study and preparation. The customer with on-site generation who wishes to net-meter would typically be responsible for the purchase and installation of interconnection equipment that meets National Electrical Code (NEC) requirements, as well as any applicable local codes. Some utilities may request or impose additional service and equipment requirements on net-metering customers. Technical issues with small generator interconnections include power quality, service reliability, equipment protection, and metering arrangements.

Policy linkages to other sectors

Net-metering will affect the economics of on-site generation and therefore would be relevant to considerations of government procurement of on-site generators. The buildings and municipal sectors would also naturally be involved in siting, noise, safety or local pollution issues.

Economic cost to the electricity sector

The customer usually pays the cost of connecting to the grid. Utilities would incur some costs if they needed to verify safety or installation quality, but as small-scale generation technologies become more standardized, and the energy service sector matures, one might expect both concerns and effort on the part of utilities to decrease.

Utilities may suffer some penalty in having to pay customers the retail rate for excess generation, instead of avoided cost, and they also may lose sales revenue, although these costs may be mitigated under appropriate performance-based regulation. On the other hand, some utilities may also benefit from net-metering, because distributed customer generation can improve distribution asset utilization and reduce system losses.

Economic effects on other sectors

Expected to result in an increase in the manufacture and installation of site-based generation.

Regional effects

Uptake of net-metering may be greatest in those regions which have accessible, good quality non-GHG emitting sources, such as wind, solar, and biomass energy, and flexible building code and land use regulations, i.e. rural regions.

Experience in other countries/Barriers to Implementation

Net-metering for small renewable energy generating systems has been available in some U.S. states for more than 10 years, but their impact on the market for renewable energy technologies has been limited[23].

The fact that participation in existing programmes has been limited can be attributed to three factors:

- *Communication.* Information on net-metering programmes has not been made widely available, and promotion has been limited. In many cases, customers are not aware of their net-metering options and/or the potential benefits derived from exercising them.
- *Economics.* Low electricity prices and high capital costs of small renewable energy systems have a big impact on residential customers' decisions in net-metering programmes. For instance, the market for small grid-connected PV systems is very small because the economics today are not favourable from the customer's perspective. Only those customers not motivated solely by financial factors have installed these more expensive systems, e.g. for environmental and/or energy independence reasons. However, even where net-metering is economic, uptake has been limited.
- *Interconnection Requirements.* Utilities often establish interconnection guidelines requiring additional protection equipment and liability insurance that add significant costs to small generating facilities. The majority of state statutes and regulatory orders for net-metering do not specify guidelines for utility tariffs, service contracts, or interconnections. In addition, utilities may include large interconnection and service fees as part of their net-metering tariffs.

A significant barrier to implementation lies in trying to persuade or mandate electrical utilities to adopt net-metering. U.S. experience has shown that several views and factors have motivated utilities' opposition:

- The imposition of additional legislation affecting their activities
- The view that paying retail prices for customer-generated electricity amounts to a subsidy because retail prices also include the costs of transmission and distribution, administration, and profits in addition to a utilities' energy cost
- Revenue losses, under price-cap or rate-of-return regulation
- The view that net-metering violates PURPA and FERC implementing rules by requiring utilities to pay higher than avoided costs for Qualifying Facility (QF) generation

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[23] Net-metering Programmes, *by Yih-huei Wan, National Renewable Energy Laboratory Issues Brief No. NREL/SP-460-21651, December 1996*

- Safety issues involved
- Loss of actual customer load information

Analysis; Table Views

Net metering can encourage site-based generation, by allowing customers to effectively reduce their net consumption. It may also entail an obligation by the supplying utility to purchase generation in excess of site requirements at a specified price.

Net metering must reduce GHG emissions to be an appropriate preparatory measure. Although well-located site-based generation can reduce line losses, and therefore system-wide emissions, the Table felt the measure should be limited to non-emitting sources, or at least those that are of lower emissions than the default alternative investments.

When selectively sited and operated, site-based generation can defer distribution or transmission investment. However, there are also concerns about "buying back" self-generation. Where rates do not reflect time- and location-specific marginal costs, the use of the same rate for sale and (effective) purchase may not be economically efficient. There are also concerns about firm availability and power quality for small operations – exchanging "high-quality grid power" for "low-quality site-based generation". At least one Table member felt net metering could cause problems in the grid in certain circumstances.

The Table, therefore, felt this measure should be limited to small systems such as rooftop photovoltaics and micro-cogeneration where grid issues are minimal or where the scale of operation does not justify separate revenue-quality metering. This measure would provide a positive sign for smaller enterprises and homeowners and complement other preparatory measures oriented to the wholesale market. The overall market and emissions impacts would be expected to be small.

8. RD & D for Longer Term Options

Financial support for research, development and demonstration: non-GHG-producing technologies.

Federal and provincial governments to provide financial support for non/low-emitting GHG technologies that are suited for Canada, for research, development, and demonstration, for transmission efficiency improvements and for mapping of the resources base.

Background

Innovation policy draws a distinction between the use of public funds to accelerate the market penetration of new, commercially-proven technologies, versus the science, engineering, testing and refinement needed to bring them to the point of commercial readiness. The RD & D considered here would belong in the latter category.

Federal government research and development (R&D) in Canada is complemented by Crown utility research institutes and provincially funded research laboratories. The allocation of funding has varied according to the government priorities. The majority of federal government non-nuclear, energy R&D funding is channelled through the Program for Energy Research and Development (PERD) which allocates money to various government departments, agencies, and institutions. PERD has funded projects in areas such as:

- Petroleum R&D: enhanced oil and gas recovery, refining, transportation and storage, oil shale and tar sands, as well as other related work
- Coal R&D: improved coal combustion, conversion, production, preparation and transport
- Efficiency and alternative energy R&D, including energy efficiency and conservation, solar heating and cooling, photoelectric systems, thermal electric systems, wind energy, energy from the ocean and biomass, geothermal energy, alternative transportation fuels, fuel cells and hydrogen.

Implementation

The recommendations of the Technology Table should form the basis of an RD & D strategy for non/low-GHG pre-commercial technologies. Any such plan will have to take into account the dominance of other countries in certain areas, and build on specifically Canadian strengths and priorities.

Agencies responsible

The Office of Energy Research and Development (OERD) would remain the focal point for co-ordinating federal energy research and development activities - with the exception of nuclear RDD - within the federal government. Any new RD & D for nuclear would be the responsibility of the industry and Atomic Energy of Canada Limited.

Policy linkages to other sectors

Any RD & D measure has strong links to both the Industry and Technology tables. Industry funding and participation are key to the development and demonstration stage of new technologies. However, industry may focus mainly on shorter-term benefits, focussing on those technologies that dovetail emissions reductions with likely success in deregulated electricity markets. Long-term research in non-emitting technologies may therefore require a greater share of government funding, unless additional economic incentives are put into place, such as market-based regulatory instruments.

Economic cost to the electricity sector

No cost, or cost reductions

Economic effects on other sectors

Improvements in non-emitting technologies may have a positive impact on other sectors that use combustion processes for electricity generation. In addition, improvements in electricity production, both in terms of cost and GHG emissions, may result in electricity substituting for fuels in other sectors.

Regional effects

Increased RD&D funding will impact on those regions that have research facilities and on regions with a resource base in the technologies being funded.

Experience in other countries

U.S.

The U.S. has made a significant commitment to RD & D in renewable and high-efficiency energy, as shown in Table 6 below:

Table 6

The 1999 Budget for Renewable, Advanced Fossil Fuel, and Nuclear Technologies in the U.S. Department of Energy ($U.S. millions)[24]

	1999 Appropriated
Total Renewable Power Technology R&D	272.3
Advanced Coal Power Technology R&D	87.7
Advanced Natural Gas Power R&D (Turbines, Fuel Cells)	88.7
Nuclear Energy Technology R&D	73.8

European Union

EU Energy RD & D activities focus on the following areas:

- large-scale generation of electricity and/or heat with reduced CO_2 emissions from coal, biomass or other fuels;
- development and demonstration of biomass, fuel cell, wind, and solar technologies;
- integration of new and renewable energy sources into energy systems;
- cost-effective environmental abatement technologies for power production.

Analysis; Table Views

Table members' support was contingent on the size of the proposed budget and the technologies it addressed. In general, however, the Table agreed that R & D spending on non-GHG-producing technologies was necessary to bring technologies with potential rapid cost reductions into commercial production.

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[24] *EERE Budget-In-Brief: Fiscal Year 2000 (http://www.eren.doe.gov/overview/budget/)*

Office of Fossil Energy, U.S. Department of Energy (http://www.fe.doe.gov/budget/00table.html)

FY 2000 Nuclear Energy, Science and Technology Budget

9. Other

9A) Remove effect of tax-induced barriers to investment in and competitiveness of no/low GHG generation

Federal and provincial governments mitigate the effect of the Specified Energy Property Rule through the allowance of flow-through or tax credits to investors related to unused Class 43.1 Capital Cost Allowance or through a rebate of unutilized CCA.

Background

A range of renewable energy and energy efficiency equipment is eligible for inclusion in CCA Class 43.1—a capital cost allowance category under the federal income tax system. Eligible technologies include certain cogeneration systems, small scale hydroelectric installations, wind energy conversion equipment, 3kW+ photovoltaic arrays, active solar heating equipment, turbine expanders or spilling engines used to generate electricity at natural gas pressure reducing stations, and equipment used in certain landfill gas applications. This can include purchased used equipment, provided that the technology remains at the same site in Canada, and is not more than five years old.

No/low GHG energy facilities typically have a significantly higher proportion of capital costs in relation to fossil fuel based facilities. The majority of the expenditure for these technologies is for the installation of permanent energy capture equipment and associated structures, not ongoing operational costs. Under the Income Tax Act this equipment is written off at a capital cost allowance (CCA) rate of 30% of the declining balance of the asset value annually. A capital cost allowance rate of 30% for Class 43.1 assets effectively allows over 80% of the cost of the equipment to be written off within 5 years. This write-off rate is thus accelerated when considering the life of many assets included in Class 43.1 (such as small hydro and wind turbines). Under current government policy, this CCA deduction is limited to an investor actively involved in the energy business (or a manufacturing and processing or mining company).

Capital cost allowance deductions are of value only to the extent that the project proponent has taxable income against which to apply the deduction. In many cases the companies involved in developing emerging technologies have little taxable income due to their stage of development. In contrast, private-sector fossil fuel based facilities are generally at a more advanced stage of development and thus are better able to utilize their capital-cost allowance deductions.

Several energy sector organizations and companies submitted recommendations to the federal government that would reduce this disparity. These suggestions included:

- establishment of a 30% CCA rate for new and retrofitted buildings and integral components that meet a specified energy efficiency performance level, for district heating assets, and for assets used for heating and cooling from renewables (currently the rate is 4%)[25];
- removing the Specified Energy Property Rules completely[26];

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[25] 1997/98 Federal Budget Submission - Energy Related Tax Measures. *Pembina Institute for Appropriate Development. Barbara Campbell and Rob Macintosh. December 30, 1996.*

[26] *IPPSTF - Independent Power Producers Stakeholder Task Force.* 1997 Pre-Budget Submission

- establishment of a category similar to Canadian Development Expense for oil & gas that can be "flowed-through" to investors in a renewable energy project[27].
- Allow unutilized yearly CCA deductions applicable to renewable energy projects to be deemed to be Canadian Renewable Conservation Expense (CRCE - see below), and/or allow $1 million / year of any development expenses associated with such projects to be converted to CRCE with similar anti-abuse rules to the CDE/CEE provisions[28].

Only a limited form of the third recommendation was adopted in the 1997 federal budget. This was the *Canadian Renewable and Conservation Expense* (CRCE) provision, which provides a deduction analogous to the Canadian Exploration Expense available to oil and gas developers, but associated with eligible renewable energy investments. CRCE is deductible at a 100% rate, can be carried forward for use against future income, and can be made available to outside investors by means of a flow-through share issue.

In general, CRCE includes intangible costs such as pre-feasibility studies, property and other costs necessary to determine the extent of the resource, evaluation, environmental and other feasibility studies, market research, and site preparation costs. The expenses currently eligible for CRCE only account for approximately 5-10% of the capital costs of an eligible project.

Implementation period

Immediate - next federal budget

Economic cost to the electricity sector

Reduced costs for affected technologies

Economic effects on other sectors

The federal government has concerns about the proliferation and possible abuse of tax shelters that allow high rate taxpayers to take advantage of flow-through and limited partnership arrangements to defer taxes. It is also concerned that other sectors may see the proposed changes as favouring the renewable energy sector, and would seek to have these or similar measures applied more broadly.

Regional effects

Currently the technologies that this would apply most rapidly to are high efficiency gas cogeneration, biomass, wind energy, and small run-of-river hydro. This would result in enhanced economic activity in Atlantic Canada, Quebec, Ontario, Alberta and to a lesser extent in British Columbia and Saskatchewan.

International trade implications

Canadian resources associated with the technologies likely to be affected are substantially better quality than most of the U.S. potential and consequently sale of output from Canadian facilities could become an export product from the electricity sector.

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[27] *IPPSTF - Independent Power Producers Stakeholder Task Force.* 1997 Pre-Budget Submission

[28] *IPPSTF - Independent Power Producers Stakeholder Task Force.* 1997 Pre-Budget Submission. *Under CEE/CDE up to $1 million dollars per year of CDE expenses can be reclassified to CEE (with 100% deduction capability), provided the company has assets of no more than $15 million. This is intended to benefit high risk, junior oil and gas companies.*

Experience in other countries

Most other countries have significant tax or other adjustment schemes (credits or subsidies) available to these technologies to help with their emergence into the mainstream of the electrical industry. Design of tax based approaches is important in order to induce desirable effects, decrease the ultimate financing costs, increase competitive forces and limit the potential for tax abuse.[29]

Necessary conditions for implementation

Suitable means of implementation must be found such that the effects of barriers can be mitigated without establishing a costly precedent.

Analysis; Table Views

Amending the corporate income tax system to remove barriers to renewable energy projects was recommended by the Table as a Quick Start item in November of 1998. Proponents assert that existing Income Tax Act provisions are of little value for the smaller, start-up and growth firms that are most active in developing such assets. These firms do not have other taxable income against which these provisions can be applied, and will likely have limited taxable project income for some time.

From another perspective, CCA write-offs should, in principle, only be usable by active investors, so that tax benefits do not flow to parties whose capital is not at risk in relation to the assets being depreciated. From this perspective, the use of CCA tax benefits by passive investors is a precedent with potentially far-reaching and adverse implications for government revenues.

The Table would like to encourage an effort to develop a method whereby the adverse investment and product price effect of existing taxation rules can be mitigated in order to achieve equivalent after-tax positions for all investors in climate-friendly projects without a precedent-setting exception to tax principles.

Creativity is needed. The corporate income tax system, which is based on profit and not physical production or environmental impact, might not be the only or best place to look. However, amending the Income Tax Act appropriately may have a positive impact on investment in climate-friendly projects, as long as reasons for such measures are clear. Otherwise other types of investment can be expected to seek similar treatment.

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[29] *Financing Investments in Renewable Energy: The Role of Policy Design and Restructuring Ryan Wiser and Steven Pickle E*nvironmental Energy Technologies Division; Ernest Orlando Lawrence Berkeley National Laboratory; University of California Berkeley, California (March 1997)

9B) Shift the basis of property taxation from capital to revenue or production

Federal and provincial governments should consider eliminating tax-induced barriers to the orderly development of no/low-GHG-emitting generation by both small and large-scale enterprises. Shifting the basis of property taxation from capital to revenue would enable developers of no/low-GHG-emitting electricity technologies to be taxed on a competitively-neutral basis with conventional fossil-fuel-based generation.

Analysis; Table and Stakeholder Views

This was a Quick Start item that was recommended in November 1998. Renewable generation technologies are more capital-intensive than their non-renewable competitors. Therefore a change from capital to revenue or production as the basis of property tax would shift electricity market share to renewables.

This measure could run into the same problem as Measure 9A) above if the change is seen as a precedent for property taxes in general. The reasons why the change is proposed – whether climate change, equitable tax treatment for producers of the same commodity or something else –could have a significant effect on its acceptability.

9C) Demand side management

By providing direct financial incentives and creative financing packages to customers, and working with trade associations, private and public utilities can encourage the efficient use of electricity and reduce the need for new power supply. Regulators and governments should work to ensure that demand side management is actively pursued in both monopolistic and competitive electricity markets.

Note: *This measure is referred to the sectoral Tables dealing with electricity end-uses*

Background

It is generally recognized that various informational and financial barriers do exist which impede fuller implementation of energy efficiency and other demand reduction actions. One such barrier exists where customers are not receiving the marginal price signal (*i.e.,* where the marginal supply cost is higher than the retail price).

There are a number of instruments, which can be used in concert to improve electrical end-use efficiency. Government efficiency standards are very effective in removing the most inefficient uses of electricity. However, there are many instances where providing information, direct financial incentives and creative financing packages while maintaining customer choices is economically preferable. These energy efficiency services could be delivered by several sources, including government-delivered programs, Energy Service Companies (ESCOs) and electrical utilities. There has been a trend in recent years for utilities to move away from providing incentives as they move towards a competitive marketplace. This does not necessarily need to be the case. Utilities that remain as regulated monopolies are in a favourable position to deliver such programs and pass a portion of the costs onto their customers (while minimizing the total cost paid by all customers). Similarly, the distribution/wires company in a competitively-priced region can deliver DSM programming and recoup the costs through a “wires” charge.

Governments and utilities can ensure that DSM programs are pursued in both monopoly and competitive market environments in order to encourage the efficient use of electricity and reduce the need for new power supply.

Some examples of potential DSM measures:

- Government efficiency standards
- building energy labelling
- expand commercial new building incentive program
- public building incentive program
- technical assistance, training, financial support for commercial
- building retrofits, multi-residential retrofits, social housing
- retrofits, residences
- faster tax write-offs for energy efficient equipment purchases
- technology commercialization program
- green procurement
- incentives to purchase energy efficient windows
- remove sales taxes from energy efficient equipment

- building permit feebates (tied to efficiency)

Agencies Responsible

Provincial and federal governments, provincial regulators

Policy Linkages to Other Sectors

Specific efficiency enhancements would be available and identified in many other sectors (*e. g* buildings, industry). The electricity sector role would relate more to a process and mechanism to transfer information and/or incentives to the individual sectors.

Economic Costs to Electricity Sector

DSM measures may cost individual electrical companies but would not be pursued unless the total cost to electrical consumers was reduced.

Analysis; Table Views

This measure was not modelled using MARKAL because the ultimate actions to enhance efficiency involve other Economic sectors being examined by other issue Tables. The electricity sector role would involve not the enhancements themselves, but information and/or incentives.

The Table generally supported this measure.

9D) Increase coal royalties.

Proponents view this measure as putting coal and gas royalties on an even basis. Others see it as a departure from the principles governing royalties and equivalent to imposing a special excise tax on coal fired electricity.

Background

A royalty represents a charge collected by the owner of a natural resource for its use. In Canada, provincial and territorial governments own most of the mineral rights, even where the land surface is privately owned, and thus set royalties on them.

In simple terms, the value of a resource in the ground is equal to its value in the market place minus the total costs (including a normal return on investment) of producing and processing it for sale in the market. This is referred to as resource rent. For a particular oil, gas or coal reserve, resource rent is determined by two factors: general scarcity of resources and differences in quality (value or cost of production) among individual deposits.

Crown royalties on energy resources vary from province to province and also by type of energy resource (coal, gas, oil, or other). Royalties are the major element of the provincial governments' system of capturing the rents on production of oil and natural gas production. Royalty rates are tied to market prices and contain elements that serve as proxies for costs of production. Coal royalties in Alberta are minuscule compared to oil and natural gas resource revenues, $15-20 million versus $2-4 billion per year, and thus attract far less attention.

Table 7

Provincial Coal Royalty Rates & Production

	Royalty Rates	Production MT
Alberta		(1997)
– Sub-bituminous coal	$.55/tonne	25.7
– Bituminous (export) coal	1% of mine mouth revenue + 13% of profit	10.6
Saskatchewan	15% of the coal contract price or deemed market value	(1993) 10.0
Nova Scotia	$. 225/tonne ($.25 per short ton)	(1995) 2.5

Source: Provincial government websites

Alberta sells a relatively small amount of coal to Ontario Power Generation, where it competes with imported U.S. coal which is the source of almost all of Ontario's coal for electricity generation. The amount and share of coal in electrical generation, by province, is shown in Table 8

Table 8

Amount and share of coal in provincial electricity production (1997)

	Generation GWh	Share of electricity production
Nova Scotia	8247	80%
New Brunswick	5866	35%
Ontario	24170	17%
Manitoba	198	<1%
Saskatchewan	11540	69%
Alberta	43924	81%

Source: Table 2.1, Appendix 3, *Electricity Foundation Paper*

In Saskatchewan, electricity prices are set by the monopoly Crown utility to recover costs, including the coal royalty. In Alberta, under the previous regulation of electricity prices and the current setting of costs for existing generation, coal royalties are also a cost element that is flowed through to consumers. For new generation, this would not be the case. In both these provinces as well as Nova Scotia, the coal royalty is a small part of the total cost of power.

Perspectives on this Measure

Proponents' Rationale

The measure is primarily designed for a competitive electricity market, where the choice of type of generation is based on relative costs. If royalties were viewed as a cost of primary energy production, differential rates between coal and natural gas, per unit of primary energy or per kWh of electricity generated would distort private sector fuel choices. This distortion would apply both to the dispatch of existing generation and to the evaluation of relative costs of new generation.

Coal and natural gas royalties may be compared to each other on the basis of energy content ($/GJ) or on the basis of electricity output ($/MWh). A $0.55/tonne coal royalty (Alberta sub-bituminous) is about three cents per GJ of heat content, or about 6% of the corresponding gas royalty.[30] However it takes about 58% more coal to produce a MWh of electricity in a typical pulverized coal plant, relative to a modern CCGT. Therefore the coal royalty is about 9.5% of the gas royalty per MWh of electricity produced by these methods. Raising the coal royalty to the equivalent per-MWh level as gas would result in an approximately 10-fold increase in royalty per tonne of coal, to $5.53. This would, in turn, add about a quarter of a cent per kWh to the coal-fired electricity production cost in that province.

According to this view:

- Under the regulated monopoly utility model, with a policy against using natural gas for baseload generation, coal royalties may not have affected generation choices.
- With Alberta having moved to a competitive generation market, it is important to establish a level playing field between coal and natural gas, the two dominant forms of generation.
- Alberta royalties on sub-bituminous coal should be raised approximately ten-fold to bring them in line with the cost of royalties per kWh for a combined cycle gas plant.

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[30] *Natural gas royalties vary with the average market price of gas, by well productivity and by vintage – pools discovered before 1974 face higher royalty rates than those discovered after 1973. For non-low-productivity well, new gas, the average rate during the past year was about $.50/GJ. The cost per would be about 0.35 cents/kWh for a typical new combined cycle generator.*

A variation on this perspective is tied to the concept of royalties as a rent collection instrument and the change in circumstances with the move to a competitive market for electricity in Alberta. Under regulated electricity prices, the Alberta government is viewed as having set low coal royalties to pass on resource rents to electricity consumers in the form of lower cost electricity than would result from setting coal royalties to capture the full resource rent. The introduction of a competitive market for electricity breaks the link between the costs of any particular generation plant and prices paid by consumers. The government should therefore re-examine its coal royalty with a view to increasing the rate to capture the rent that would cease to flow through to consumers.

Opponents Perspective

Opponents of this measure view the difference between natural gas and coal royalties per kWh as reflecting the difference in the value of the resources. With gas prices determined by North American markets, electricity generators have to pay the market price, regardless of royalty rates on gas in Alberta. This point is illustrated by the range of royalties paid per GJ of gas within Alberta and between Alberta, British Columbia and Saskatchewan, while there is a common price for gas in the market regardless of its source.

Alberta's sub-bituminous coal appears to have no economic use other than on-site generation of electricity. Sub-bituminous coal rent is determined by the market price for electricity over the life of the generation plant associated with the mine, minus the total cost of generation and mining, including a normal return on investment. Thus the rent per tonne and per kWh varies with the generation costs and mining costs and coal quality, as well as the price of electricity. High quality deposits – those with higher-grade ore and lower mining costs – have higher rent than lower quality deposits. Neither bears any necessary relationship to the value of natural gas resources used in electricity generation.

If, excluding coal royalties, coal generation is lower cost than alternative types of generation, the rent on a particular coal mine is the royalty rate that would just allow the generation using that mine to undercut or match the cost of the next lowest cost alternative type of generation. Obviously, a royalty of $.55/tonne would only be equal to the rent for a particular mine by coincidence. Similarly, a flat rate for all Crown coal cannot be precisely equal to the rent on each mine, since they all differ in quality. From the perspective of the government capturing the rent on Crown resources, the question is whether the royalty rate roughly approximates the rent.

All current production of sub-bituminous coal and therefore all royalties are connected with existing generation. In Saskatchewan there is no change in pricing. In Alberta, the coal royalties are a cost element in the new power purchase agreements that will cover the remaining economic lives of existing plants, or at least run to 2020. To the extent that Crown royalties are below the full resource rent, consumers will continue to benefit under the restructured arrangements for existing coal plants. An increase in these royalties would represent an unfair increase in costs imposed on existing contractual arrangements.

For new coal plants, it is not clear that coal royalties are less than resource rent. Coal does not appear to be able to compete with natural gas, which is capturing all the planned new generation.

Implementation

To affect planning decisions on new plants, there would have to be a long notice period to cover the planning and construction lead-time for coal plants.

Agencies responsible

Coal royalties are within provincial jurisdiction.

Economic cost to the electricity sector

Where coal is currently competitive with natural gas and other types of generation, a sufficiently large increase in coal royalties could make it uncompetitive and induce a shift to other types of generation. For existing coal generation plants, an increase would raise their operating costs and make them less competitive at the margin and impose losses on coal producers or power companies. Coal royalties *may* have an impact downstream in the generation of electric power by coal-fired power stations. If the price of coal goes up as a result of the royalty increase, the market share of coal among generation types may go down and therefore so would GHG emissions, given that coal-fired electricity contains more GHG emissions per kWh than any other major generation type. The extent to which an increase in coal royalty would increase the price of coal is determined by the extent of competitive supply to coal-fired power plants from jurisdictions in which the cost of coal production would be unaffected by the measure (i.e. the U.S.). All else equal, the fewer competing American suppliers, the more pronounced the coal price increase would be and similarly for the electricity production market share shift. In Canada, the coal price impact would likely be largest in Alberta and perhaps Nova Scotia, where coal supply tends to be "tied up", but it would be small in Ontario, where U.S. coal is regularly imported. If Ontario has a perfectly competitive coal market for example, the royalty increase would have no effect there.

A full treatment of the effect of coal royalty changes would require detailed information on market shares of coal by source and a simulation of the new equilibrium in North American coal markets induced by the change in royalties. Some heuristic assumptions are made here in order to illustrate the effect on production costs, market shares and emissions.

Modelling: The extent to which a coal producer can pass on its costs of a royalty increase depends on the competitive structure of the market. In Alberta, there are, and would be no serious competing importers from the U.S., unless the royalty increase were very large. However, Ontario Power Generation can buy a lot more from the U.S. for small differences in price. Coal producers selling in Alberta would be able to pass on the full royalty increase, while any Canadian coal producer would lose its full share of the Ontario market unless it absorbed the royalty increase. There would be little or no fuel substitution in Ontario. Fuel substitution in Alberta would depend on the impact of the increase in coal price on electricity production costs, relative to the cost of gas-fired electricity.

For the purposes of modelling, the Table assumed a 10-fold coal royalty increase –a $5/tonne increase in the royalty for Alberta, Saskatchewan and Nova Scotia – making coal and natural gas royalties approximately equal, per kWh of electricity. It assumed that the full increase would be passed on in each province but Ontario, where it would have no effect. Under these assumptions the cost of coal-fired electricity went up about 0.25 cents/kWh outside of Ontario. This was not enough to induce coal-to-gas substitution in the model. These results suggested the effect of the assumed royalty increase on emissions would be small.

Economic effects on other sectors

The effects of this royalty increase would be more focused within the electricity sector than (say) a comparable increase in oil or natural gas royalties, because thermal coal's almost-unique application is in power production. The modelling results suggest that demand for coal drops proportionally less than the price of coal increases, meaning net incremental provincial government revenue from the royalty increase. To the extent that such an increase caused a switch from coal to natural gas generation, gas production would probably be diverted from the export market to provincial electricity generation. However, the net overall economic effect of increased coal royalties cannot be predicted within the modelling framework utilized by the Table. Sub-bituminous coal in Alberta and lignite in Saskatchewan appear to have no alternative economic use to mine mouth coal-fired electricity generation. Alberta and B.C. bituminous coal is exported to foreign coking coal and thermal markets, with a small amount of thermal coal competing with U.S. coal in Ontario.

Regional effects

The distribution of electricity sector impacts among provinces is discussed above. Alberta, Saskatchewan and Nova Scotia could experience a minor contraction in coal-mining-related activity, with a diversion of gas from export markets to local electricity generation.

International trade implications

Note that the discussion and analysis above does not assume any corresponding activity by the U.S. Therefore U.S. coal would, all else equal, increase its share within Ontario and perhaps Nova Scotia, Manitoba and Saskatchewan. As discussed above, natural gas exports from Canada to the U.S. would likely decrease. To the extent that electricity costs and prices increased in Canada, electricity imports could increase and exports decrease.

Certain provinces with coal-fired generation also export to the electricity to the U.S., as indicated in Table 9:

Table 9

Exports of coal-fired electricity generation and percentage of total provincial electricity exports

	Exports (GWh)	**Share of Exports**
New Brunswick	380	15%
Ontario	3971	76%
Saskatchewan	176	100%
Canada	**4552**	**11%**

Source: Table 6.3, Appendix 3, *Electricity Foundation Paper*

Experience in Other Countries

Direct comparisons with other countries are complicated by differences in coal qualities and properties, and in the different distances from mine to point of use (transportation costs).

Areas for further research

Further analysis to determine the change in emissions in the context of competitive coal markets and in relation to ongoing market restructuring and non-GHG emission control.

Table Members' Views

As outlined above, there are two different perspectives on this measure at the Table:

1. Royalties are a government-imposed cost on fuel used to generate electricity.

Proponents see this royalty difference as a government determined competitive advantage for coal that should be eliminated by raising coal royalties.

2. Royalties are the major element of the government's system for capturing rent on Crown resources.

According to this view:

- The issue of coal royalties is a matter of the government capturing the full rent on Crown resources.
- An attempt to capture more than the full rent on a new mine for a new generation project would result in the project not proceeding and the government capturing no rent.
- Royalties on coal only become significant for competition between coal and other forms of generation if they are set too high to allow coal to proceed.
- There is no reason to expect the rent per kWh to be the same for coal, natural gas, hydro, uranium, oil or wind, and therefore no reason to set the royalties on one of these in relation to any of the others.
- The difference between natural gas and coal royalties reflects differential resource values. The fact that natural gas appears to be the fuel of choice for new generation in Alberta indicates that coal royalties are not too low. They could in fact be too high.

Additional views: There were concerns about adverse GHG emission effects of the measure: an increase in coal price is a disincentive to capture and sequestration investment by coal-fired plants. This is an economic inefficiency caused by taxing the fuel, not the emissions. To illustrate this, note that a credit equal to the resulting increase in the cost of coal could be awarded to the sequestration investor. But there is no reason why such an amount would be related to the price of emissions.

Table Support: General lack of support. There was broad reluctance to target one fuel or (*de facto*) the few coal-producing provinces, although those speaking in favour cited level playing field arguments and pointed out that any effective measure will have different effects on different regions.

Section 5 Commitment Period Measures

Measures for Significant Reductions Prior to a Commitment Period

Credit for Early Action

The design options and evaluation of impact of a credit for early action measure are the mandate of the Credit for Early Action Table. The Electricity Table discussed it only in a general way.

Credit for early action is explicitly focussed on near term reductions as part of a phased approach to emission reductions. In general terms, the example used for discussion by the Electricity Table has the following characteristics:

- Baselines would be specified for entities who choose to participate in the program. These would be the reference levels of emissions for calculating reductions.
- The form of credit received would be a government GHG certificate, measured in tonnes of CO_2 equivalent for use in the future. The certificates could be used in compliance with any future GHG policy measure – whether tax, emission trading system or regulatory standard.
- The value of the certificates as a risk management instrument would create the incentive for entities to opt into the program and reduce emissions in the near term. The certificates would be transferable and thus a market price for them could be established though the trading aspect would be secondary. *[Many entities would be likely to choose to retain the certificates for their own risk management purposes, which could result in little actual trading].*
- The issuing of the certificates would represent a pre-allocation of permits or distribution of new tax revenues that would otherwise flow to governments if and when policies to constrain GHG emission are imposed in the future.

Table Views

The Table supported the principle of credit for early action to elicit near-term reductions, provided that the reductions are real, verifiable and transparent.

Commitment Period Measures

Emission Pricing in a Kyoto Commitment Period

Emission pricing provides a price incentive for individuals and firms to reduce emissions. The two types of emission pricing identified by the Table are:

Emission Trading System

The design options of emission trading systems are the mandate of the Tradable Permits Working Group. In general terms, the example used for the Electricity Table's purposes has the following characteristics:

A permit (CO_2 certificate issued by government) is required for the emission content of hydrocarbon fuels and for other GHG emissions that are monitored directly. In the case of certificates for the emission content of hydrocarbon fuels, the certificate requirement could be imposed on the user of the fuel or upstream of the user.

The government-created certificates are allocated or distributed in some fashion, and trade in certificates establishes their market price. (e.g. the allocation could take the form of specifying baselines. If actual emissions were above the baseline, certificates would be required; if below, the government would issue certificates.) The allocation issue is a critically important aspect of the permit system.

By reducing direct or indirect emissions by one tonne, consumers of hydrocarbons and emitters of other GHGs save the cost of a 1-tonne certificate that is required of end use emitters or reflected in the retail price of fuel. (By reducing fuel consumption they save both the cost of the fuel itself and the additional cost of the permit included in the retail price.)

GHG Tax or Levy

A tax or levy is imposed on the emission content of hydrocarbon fuels and for other GHG emissions that are monitored directly.

By reducing direct or indirect emissions by one tonne, consumers of hydrocarbons and emitters of other GHGs save the cost of the tax or levy on 1-tonne of emissions that is imposed on end use emitters or reflected in the retail price of fuel. (By reducing fuel consumption they save both the cost of the fuel itself and the additional cost of the tax included in the retail price.) For the tax or levy approach to pricing, the critical allocation issue takes the form of the manner in which the tax revenues are recycled.

Implementation

Emission pricing would be implemented as a broad, economy-wide measure during a commitment period.

Agencies responsible

The federal and provincial governments would have to work out the jurisdictional aspects of implementing a harmonised system across all provinces and territories. This would likely vary depending on the form of emission pricing implemented.

Policy links to other sectors

This measure would apply where administratively feasible to almost all sectors.

Economic cost to the Electricity Sector

The economic cost to the electricity sector would depend on the overall national target, the impact of emission pricing on the price of electricity and the method of allocating permits or tax revenues.

The cost of changes in the mix of generation estimated by the Table's modelling analysis depends on the scenario chosen and the target of emissions chosen. The table below summarises the emission price, the emissions reduction, the change in electricity prices and present value of costs over 30 years for the various scenarios analysed by the Electricity Table for illustrative purposes. The introduction of emission pricing to change the mix of generation would also require some method of dealing with the resulting stranded generation assets. Those methods have not been identified in the Table's work.

Table 10

Impact of Scenarios on Emission Prices, GHG Reductions, Average Electricity Prices and Cost

Scenario	**Emission Price in \$/tonne CO_2 for 94% of 1990 emissions in 2010**	**Reduction (Mt)**	**Average Increase in Electricity Price in 2010 Cents/kWh**	**Present Value of Cost* over 30 Years (\$Billions - Gross)**
NRCan Base	12.19	28	0.5	3.9
Low discount rate (4%)	6.28	27	0.3	5.7
Gas at \$6/ GJ	27.28	64	1.5	10.7
High Demand	30.48	66	1.2	18.0
No Bruce A	15.33	36	0.8	5.0
No new Large Hydro	14.34	33	0.7	5.9

* Note: Present value cost is calculated at 7% discount rate, except with the 4% discount rate scenario.

Economic cost to other sectors

Model analysis indicates that introducing emission pricing would lead to an increase in the price of electricity to cover the higher cost of the new mix of generation and the permit or tax cost on fossil generation.

The impact on electricity consumers of this increase in price has not been analysed by the Electricity Table.

The Table's model analysis is illustrative. The impact on the electricity sector and other sectors of introducing emission pricing to reach the Kyoto target, can only be analysed in the roll-up of sectors and measures.

Regional effects

The analysis illustrates that reaching a national target in the least cost manner requires differential actions across regions. These effects, which vary by scenario, are shown in the detailed model results in Annex B. Like all of the Table's analytical results, these results are based on an examination of the electricity sector in isolation. The overall effects can only be shown in the roll-up analysis.

International trade implications

There are two aspects to the international trade implications: the effects on electricity trade and the effects on other sectors through the increase in the price of electricity. These can only be examined in the roll-up analysis.

Necessary conditions for implementation

For the Electricity Table, key conditions would be designing mechanisms to deal with stranded assets, addressing other aspects of the allocation issue in a fair manner, and ensuring access by electricity generators to lower cost emission reductions in other sectors and other countries. Some environmentalists on the Table support emissions trading provided that it results in independent, transparent, and verifiable emissions reductions, the majority of which occur domestically.

Areas for further research

The analytical results of the MARKAL model reflect the assumptions that go into the model. The explicit assumptions about technology costs have been reviewed by Table members and represent their best information available in the time available to review them. Often, questionable assumptions are only revealed through the results of model runs. A number of these are likely to arise in the roll-up analysis. There are also a number of *implicit* assumptions built into the structure of the model, including: perfect foresight, completely efficient decisions, perfectly functioning electricity markets, and absence of regulatory or other impediments to efficient timing of additions to capacity. The effect of real world differences from this assumed model world needs to be considered in any evaluation of the cost of measures.

Analysis; Table Views

If mandatory policies are to be adopted to meet an emission constraint, emission pricing would be preferred over mandatory standards, quotas, or other administrative directions as a way of bringing about emission reductions, subject to dealing in an acceptable manner with two important aspects of the policy:

The measure allows for the allocation of the cost burdens and gains that would result from global and Canadian policies to constrain GHG emissions

The measure should provide access to lower cost actions to reduce emissions outside the sector and outside Canada.

Generation Portfolio Standards

Generation portfolio standards would regulate the minimum percentage of generation comprised of non-emitting technologies.

These are most easily applied in jurisdictions with monopoly distribution utilities that build or contract for all the power supply of consumers in their franchise area. The higher costs of turning to non-emitting sources of generation get rolled-into the total generation costs of the distributor and charged to customers.

Where there is retail competition, the standards would either be applied to retailers, allowing some form of trading mechanism for compliance, or converted into a price subsidy, with the cost picked up by the system operator and charged to all consumers through an add-on to the wires costs.

Implementation

Binding portfolio standards would be implemented as a sector specific measure during a commitment period.

Agencies responsible

Provincial governments and regulatory agencies would presumably have responsibility to implement standards. The standards would need to be harmonized across jurisdictions to avoid creating additional distortions.

Economic cost to the Electricity Sector

The economic cost to the electricity sector would depend on the specific design and change in generation mix imposed. For any given reduction in emissions, the cost would exceed that resulting from emission pricing to the extent that the mix of generation diverged from the cost minimising mix under emission pricing.

The costs of meeting a portfolio standard requiring emerging, non-emitting technologies to be 3% of generation in 2005 and 5% in 2010 is shown in Table 11 below:

Table 11

Cost of Meeting Portfolio Standard of 3% Non-emitting Technologies

	Marginal Cost of Reductions $/tonne	Reduction Tonnes (Mt) in 2010	Present Value of Cost* over 30 Years ($Billions)
Binding Provincial Standard	76	10	8
National Standard	38	10	4
Emission Pricing	12	28	4

* Note: Present value cost is calculated at 7% discount rate.

Economic cost to other sectors

The price of electricity would have to increase to cover the higher cost mix of generation. The impact on electricity consumers of this increase in price has not been analysed by the Electricity Table.

Regional effects

The binding provincial variant of this measure would impose large variations in costs across regions due to the differential availability of generation options. This points to the necessity of recognising that difference in the design of any measures.

International trade implications

The increase in generation costs would have trade implications for both the electricity sector and its customers. These need to be examined in the roll-up analysis.

Experience in other countries

Several U.S. states including Arizona, Nevada, Massachusetts, Connecticut, Maine and Vermont have already implemented programmes. Other states such as California, Rhode Island, New York, Wisconsin and Illinois are approaching renewable energy development and deployment through the collection of Systems Benefit Charges (SBC). Some, such as Massachusetts are using both, by splitting off market development to the RPS and ensuring continued research through the SBC.

At the federal level, U.S. President Clinton's Comprehensive Electricity Competition Plan recommends a minimum 7.5% non-hydroelectric, non-imported renewable tradable portfolio standard by year 2010. In recent years, both the Administration and individual members of the U.S.Congress have introduced several RPS proposals. Each bill proposes different targets spanning different time periods and with different eligibility criteria. The bills specify that a minimum percentage of U.S. electricity generation or sales be obtained from renewable energy sources, whose definition may vary. This percentage ranged from 4 percent in 2010 under an earlier bill by Rep. Schaefer to 20 percent in 2020 under the Senator Jeffords bill, representing an increase in renewable energy use ranging from 10 percent to more than five times the projected business-as-usual levels. One feature common to all proposals at the federal level is the proposal to create a national renewable energy credit trading market to implement the RPS.

Necessary conditions for implementation

Determining the level of the standard is the most difficult decision in portfolio standard implementation.

Determining eligible resources and technologies will be an issue, especially where hydro is a competitive resource. A two-tiered system may be one way to overcome this problem, by applying a separate portfolio standard to separate bands of technologies. Province-by-province portfolio standards would have to be sufficiently harmonised to allow trading and full development of lowest-cost energy resources on a national basis.

Analysis; Table Views

Most members of the Table view portfolio standards as a highly prescriptive approach that is more costly and less efficient than an appropriately designed emission pricing system. It should be noted, however, that some environmentalists on the Table were strongly in favour of this measure.

ANNEX A - REFERRED MEASURES

In the fall of 1998, the Electricity Table developed a 'quick start' proposal on possible modifications to the tax system to eliminate tax-induced barriers to the development of low-GHG augmenting generation. The Table also gave consideration to the following measures for lowering GHG emissions:

- Strengthening consumer information programs to encourage efficiency and the choice of low GHG-emitting technologies or fuels;
- Support for strengthened voluntary action;
- Encouragement of an industry/government and NGO partnership on Joint Implementation and Clean Development Mechanism; and,
- Early establishment of a bilateral emissions trading system with the U.S.

The Table considered these latter measures to have merit. However, their scope extends beyond the electricity industry, and hence beyond the capacity of the Electricity Table to thoroughly analyze them. The Table supports these measures in principle, should they be included in the recommendations of the appropriate Tables.

A brief description of each of these measures follows.

Measure: Financial Support for New Low-GHG Augmenting Electricity Generation

The Electricity Table discussed this item in the fall of 1998. It recommends possible changes to the Federal and Provincial tax systems to eliminate tax-induced barriers to the development of low GHG-augmenting generation. It is aimed at reducing barriers to non/low GHG emitting generation such as: disincentives for investment, trapped or stranded legislated write-offs and obstacles to technologies with higher percentage capital costs.

The Table recommended this item to the NAICC-CC as a potential 'quick start' element of the Climate Change Implementation Strategy in December of 1998 (a copy of the referring letter with attachments follows).

The Table generally supports this type of initiative. Measures 9A, Remove effect of tax induced barriers to investment in and competitiveness of non/low GHG emitting generation, and 9B, shift the basis of property taxation from capital to revenue or production, from the preparatory measures section of this paper, include elements of this quick start item.

This quick start item would tend to encourage and increase the market share of non/low GHG emitting technologies.

December 7, 1998

David Oulton
NAICC-CC, Co-Chair

John Donner
NAICC-CC, Co-Chair

Dear David and John:

Please find attached a Quick Start proposal that the Electricity Industry Issues Table discussed and accepted at its last meeting on November 26 and 27. It recommends possible changes to the Federal and Provincial tax systems to eliminate tax-induced barriers to the development of low GHG-augmenting generation.

The Electricity Table recommends this item as a potential 'quick start' element of the Climate Change Implementation Strategy.

Yours sincerely,

John Lowe
Electricity Table Secretariat

on behalf of:
Rick Hyndman and Richard Drouin
Co-Chairs

Electricity Industry Issues Table

(Attachments)

cc Electricity Industry Issues Table

Proposed Quick Start Item:

November 30, 1998

Financial Support for New Low-GHG Augmenting Electricity Generation

Description of the initiative (including potential national or regional applications)

Federal and provincial governments should consider eliminating tax-induced barriers to the orderly development of low-GHG-augmenting generation by both small and large-scale enterprises. Currently most developers of low-GHG-augmenting generation are unable to fully utilise the legislated write-off rates designed to encourage implementation.

Low-GHG-augmenting generation includes electrical generation from resources such as wind, solar, biomass, small and run-of-river hydro and waste reduction processes such as flared solution gas and landfill gas reclamation.

Barriers that should be eliminated are:

- Disincentives for investment
- Trapped or stranded legislated write-offs
- Obstacles to technologies with higher percentage capital costs vs ongoing expenses

Possible Mechanisms for Governments to Remove Tax-induced Barriers:

Potential Federal Tax Change Options:

For low-GHG-augmenting generation, eliminate the Specified Energy Property Rule in Class 43.1 which currently limits the ability of corporations to claim CCA deductions in respect of such property against income from all sources, to those corporations whose principal business is energy, manufacturing and processing or mining.

Allow unutilized deductions derived from Class 43.1 expenditures to be reclassified as CRCE, with the ability to renounce these expenditures to investors via a flow-through share agreement. This would allow improved investment potential by common share investors in the construction activities of primary producers of renewable energy, analogous to other primary energy resources such as petroleum and mining.

Create a refundable tax credit for unutilized Class 43.1 CCA write-off for companies not able to fully utilize the legislated rate against other income.

Provincial Tax Measures

Restructure property taxes (Provincial) on renewable energy resource developments. Currently the high % capital costs of such developments increases the property tax amount per kWh relative to similar electrical output levels from other generators who burn fossil fuels and have lower capital costs as a percentage of product costs.

Inclusion of Certain Technologies Currently Excluded from Class 43.1

Include electrical generation equipment to utilize solution gas, which would otherwise be flared as qualifying assets for Class 43.1.

Include district heating and community energy systems utilizing waste heat from electrical generation as qualifying assets for Class 43.1.

Roles and Responsibilities of Partners/Sponsors

Independent power producers, the Canadian Electricity Association and various environmental advisory groups have listed this issue at the top of their list of actions that would improve the introduction of cleaner and lower GHG technologies.

Implementation Schedule

Immediately available through both the Federal Budget process and provincial property tax reviews. Much of the groundwork has been accomplished in this area within various government departments and is currently at a stage where the political will to institute these measures is required.

Brief History of the Initiative (outlining available analysis of initiative, evidence of broad-based support)

These initiatives and derivatives have been discussed by various industry and governmental think tanks such as the National Round Table on the Economy and the Environment, the IPP Stakeholder Task Force, environmental groups such as the Pembina Institute and various initiatives of the Canadian Electrical Association.

GHG reduction potential and economic/social/environmental benefits

Enhanced rate of capital stock turnover will result in jobs and activity in the electricity sector. Building healthy new Canadian businesses in the independent power generation sector will ensure that at least a portion of this sector will be domestically controlled. In most jurisdictions new electrical resources will be needed in the near future and export opportunities for cleaner resources are becoming increasingly more attractive.

Lowering the carbon intensity per kWh of electricity generated in Canada will contribute to successful meeting of GHG reduction targets where it displaces hydrocarbon-fired generation.

Identification of Major Risks or Barriers

Any modifications to the tax system will cause concerns regarding tax abuse. The methods indicated above utilize well proven techniques to enhance investor interest and improve the efficacy of currently legislated write-off rates.

Identification of Costs

Increased tax receipts caused by increased economic activity offset tax costs of these measures. Jobs associated with equipment manufacturing, construction and sales will result in higher indirect tax receipts through a significant multiplier effect. Development of a strong renewable sector will result in local manufacturing and development of additional export opportunities in both the produced energy and the potential for equipment export.

Description of How Effectiveness/Results will be Monitored and Evaluated

Most of the measures illustrated are activity based such that the only costs are with actual activity. This will allow a direct measure of the effectiveness of the program given that new electrical generation development at the current time is at a standstill.

Names and Addresses of Contact Persons Sponsoring the Initiative

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Measure: Strengthen Consumer Information Programs to Encourage Efficiency and the Choice of Low GHG-emitting Technologies or Fuels. Assess and Build on Existing Programs.

This measure was discussed briefly by the Electricity Table. It proposes increasing the use of mass communications media, such as television, to promote actions by consumers that increase energy efficiency and reduce GHG emissions. It proposes an initial market study to assess current programs and to determine ways to improve or add to them.

The Table decided that this measure extended well beyond the electricity sector and referred it, with support in principle from the Table, to the Climate Change Secretariat for potential consideration by the Public Education and Outreach Table (a copy of the referring letter with attachments follows).

The Table generally supports this type of initiative. It recognizes that such consumer education programs already exist in limited form and recommends strengthening these programs through greater use of television, radio etc.

This measure would affect the electricity sector to the extent that consumer demand is reduced by a move to more energy efficient products and services. The measure would affect, in particular, the residential, commercial, industrial, appliance and equipment, and transportation sectors.

October 21, 1998

Anne-Marie Smart Co-Chair Public Education & Outreach Table	George Foote Co-Chair Public Education & Outreach Table

Dear Anne Marie and George:

Please find attached two versions of a Quick Start proposal that the Electricity Industry Issues Table discussed at our last meeting on October 5, 1998. This action concerns the role that electric utilities could play in providing consumers with information about the climate change issue, the importance of their role and the effect of their consumption decisions on GHG emissions.

During our discussions, it was decided that this Quick Start proposal is one that could best be considered by the Public Education and Outreach Table, as it is, at its heart, a matter of public education and communication.

The Table reached consensus in support of Version 1, which is a general formulation of the concept. Version 2 is a more fully developed and specific proposal. The Table was sharply divided on the merits of this more detailed version. However, some members felt strongly that it should be examined by the Public Education and Outreach Table. The Electricity Table agreed that it should be forwarded for your attention along with the consensus version.

In forwarding this proposal, we ask that the Public Education and Outreach Table consider the merits of both versions as a Quick Start element of the Climate Change Implementation Strategy.

Could you please let us know the results of your deliberations.

Yours sincerely,

John Lowe
Electricity Table Secretariat
on behalf of:

Rick Hyndman and Richard Drouin
Co-Chairs
Electricity Industry Issues Table

(Attachments)
cc Climate Change Secretariat
Electricity Industry Issues Table

Proposed Quick Start Item

October 5, 1998

Version 1:

Electric Utilities Role in Providing Information for Consumers

Description of the initiative (including potential national or regional applications)

The electric utilities could support the implementation of a strategy to provide consumers with information about the climate change issue, the importance of their role and the effect of their consumption decisions on GHG emissions.

What the electric utilities do and the message they convey should be developed in the context of and as part of a coordinated and comprehensive strategy covering the other sectors, governments, etc. who need to be involved.

Version 2:

Electric Utilities Role in Providing Information for Consumers

Description of the initiative (including potential national or regional applications)

Implementation of a multi-sector strategy to provide consumers with information about the GHG emissions content of their day-to-day activities.

All electric utilities and distributors should disclose, attached to their periodical bills to their consumers, the following information:

- The proportion of each fuel type used in generating the electricity distributed.
- A standard list indicating the quantities of GHG emitted by each fuel type (expressed in CO2 equivalent).
- The yearly GHG emissions (expressed in CO2 equivalent) corresponding to the specific consumption of that consumer.
- A federal-provincial government standard statement expressing Canada's commitments and objectives in GHG reduction.
- Utilities and distributors would be encouraged to add their own publicity stressing their own commitments and objectives in GHG reduction and their specific actions on the issue.

In order to ensure a level playing field between sectors and with other energy players:

- Natural gas and heating oil utilities and distributors would be subject to a similar requirement.
- Similar information would be posted at each fuel pump, stating the quantity of GHG emissions resulting from a fill-up.
- Similar information would be posted at train, metro and bus stations or terminals, stating the GHG emissions per passenger corresponding to a standard trip.
- Similar information could also be provided by other types of GHG emitters.

Implementation Schedule

Can be implemented immediately. The best strategy is to implement these requirements simultaneously in the various sectors.

Brief History of the Initiative (outlining available analysis of initiative, evidence of broad-based support)

There is already a widespread support in the U.S. for disclosure by electric utilities of the environmental content of their distributed product (to ease consumer choice). In Canada, the Sierra Club also recently supported such an initiative in Ontario.

We believe that the initiative however must not be limited to electric utilities. Other energy players and sectors, partially responsible for the overall GHG emissions, must also be subject to a similar requirement, as outlined above.

Estimation of GHG reduction potential and the economic/social/environmental benefits

The main objective is to prepare public consciousness about the seriousness of the issue. This will help implement further measures in the future that may be costly or involve a change in consumers habits.

A secondary objective is to ease consumer choice of energy when available. This secondary objective is more present in the U.S. than in Canada.

Identification of Major Risks or Barriers

Using scientific uncertainty or uncertainty as to the exactness of the GHG measurements to delay this measure indefinitely.

Avoiding decision by passing this issue to another Table (which in turn could find reasons for passing it back to the Electricity Table).

Identification of Costs

Extremely low.

Description of How Effectiveness/Results will be Monitored and Evaluated

Effectiveness will be measured by the public's positive response to future measures the governments could propose on GHG reductions, measures that could involve costs to consumers or changes in habits.

Names and Addresses of Contact Persons Sponsoring the Initiative

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Measure: Support for Strengthened Voluntary Action

This measure was discussed briefly by the Electricity Table. It proposes that the Ministers of Energy and Environment issue a statement that large point-source emitters from all sectors are expected to be participants in the Voluntary Challenge and Registry, and strongly urging them to consider participation in additional voluntary measures such as a credit for early action system, the GERT pilot, and the JI/CDM program. Ministers would also urge smaller emitters in all sectors to participate in the VCR or EcoGeste. Finally, governments should agree, as an indicative price signal, that all sectors should take advantage of emission reduction opportunities costing no more than \$3.00/tonneCO_2. However, this should not be understood as a low-level carbon tax.

The Table decided that this measure extended well beyond the electricity sector. The Table generally supports this type of initiative in principle. It recognizes that voluntary measures have real costs associated with them, and that a strong recommendation by Ministers would increase participation in voluntary measures by providing an indication regarding the future regulatory environment.

This measure would affect the electricity sector by increasing investment in GHG-mitigation capital equipment by utilities, and by making it easier for non-utility power producers using non-emitting alternative technologies to enter the market. It would also affect capital investment in GHG-mitigation equipment by other sectors.

Measure: Encourage Industry/Government and NGO Partnership on Joint Implementation (JI) and Clean Development Mechanism (CDM)

This measure was discussed briefly by the Electricity Table. It proposes that the federal and provincial governments promote government/industry/NGO partnerships, including the identification of Joint Implementation (JI) and Clean Development Mechanism (CDM) opportunities around the world. This promotion should include the use of trade missions to increase foreign awareness of Canadian capabilities, and to facilitate access to foreign decision-makers by Canadian companies.

The Table generally supports this type of initiative in principle. It recognizes that partnerships between industry, government and NGOs will be key to the effective implementation of the Kyoto Mechanisms.

This measure would enhance the ability of the electricity sector to take advantage of low-cost opportunities both domestically and outside Canada, as well as enable companies within the sector to pool their resources, thus lowering finding costs for offset opportunities in foreign markets. The proposed partnerships should not be constrained to the electricity sector, and should encompass other fossil fuel users and large-emitting sectors.

Measure: Early Establishment of Bilateral Emissions Trading with the U.S.

This measure was discussed briefly by the Electricity Table. It proposes that consideration be given to the early establishment of a North American emissions trading system that could help to achieve Canada's and the United States' emission reduction objectives. Any such trading system would have to be based on the principles of: economic efficiency; least-cost options for the Canadian economy; inclusion of all economic sectors; consideration of all types of reductions (*e.g.,* energy efficiency, substitutions and offset measures); independent, transparent, verifiable emissions reductions, harmonization with U.S. efforts; equitable sharing of the burden among Canadian regions; and, consistency with the eventual Kyoto mechanisms. Table decided that this measure extended well beyond the electricity sector. The Table generally supports this type of initiative in principle. It recognizes that some form of emissions trading system will be key to the effective and economically-efficient implementation of the Kyoto Mechanisms. , Some Table members are of the view that a majority of reductions should occur domestically.

For the electricity sector, this measure would take advantage of low-cost opportunities within the U.S., and allow for the least-cost mix of generation and sequestration to meet the Kyoto targets. Since all sectors with high emissions will likely have to adopt similar emissions trading mechanisms, inter-sectoral trading of permits will further enhance the number of cost-effective opportunities for reducing GHG emissions. In addition, given that the U.S. is Canada's major trading partner, it will be critical to ensure that Canada's movement towards a permit trading system is coordinated with similar U.S. measures.

ANNEX B. MODELLING RESULTS

Process:

The Table contracted with private-sector consultants (Haloa, Inc., GCSI and others) for the use of an economic model (E-MARKAL), collection and verification of data, and consultation with provinces, as necessary in order to:

- estimate the relative cost of reducing GHG emissions from the electricity sector;
- develop appropriate measures;
- analyze the impact of proposals;
- analyze and interpret the results.

The E-MARKAL model was selected because of its intrinsic capabilities and also, in part, because it already incorporated existing data on the electricity-generating sector. Thus, the data-gathering process was simplified by allowing the Table to focus on the verification and updating of data in the model. Consultants, and, in some cases, Table members undertook to verify the data and in cases where confidentiality was a concern, the relevant utility was consulted for confirmation of the accuracy of the data.

The consultants also provided the Table with a workshop to examine, in detail, the capabilities of the model, and the assumptions on which it was based.

Structure of the E-MARKAL Model:

The E-MARKAL model is a subset of Haloa's MARKAL model, and unlike the latter – which models the whole economy – models only the electricity sector. This approach was taken because the mandate of the Table required it to examine climate-change proposals affecting the electricity-generating sector, in the context of a fixed set of assumptions about the rest of the economy. Examining the economy-wide interaction of the proposals of all 16 Tables is the mandate of the Analysis and Modelling Group.

The E-MARKAL model used by the Table is a detailed model of Canada's electricity supply system. It contains data and forecasts of domestic electricity demand and exports, of technology, labour and fuel costs, of transmission and generation capacity and of resource limitations. In effect it takes existing capacity, builds new capacity as required to meet demand and operates the electricity supply system. It does all this so that load is served in the least-costly way from the perspective of the Canadian economy as a whole. For the purposes of the Table's analysis, a national carbon constraint was introduced into the model, and a new least-cost mix of generation was derived to meet the constraint. The analytical methodology therefore can be viewed as applying a Canada-wide, sector-specific cap on carbon dioxide emissions, and allow emissions trading at a price equal to the marginal cost of abatement; in effect, emissions pricing.[1]

Merits of This Approach:

Use of a model such as E-MARKAL allows for the derivation of *cost curves*, *i.e.*, numerical solutions that can show graphically the relationship between emissions reductions and the cost of reducing emissions, assuming that industry always configures itself in a manner that minimizes its costs. Cost curves produced by E-MARKAL also yield information about the effects of emissions constraints on the resource mix, on interprovincial electricity trade and transmission line construction, and on the marginal cost of electricity (*i.e.*, electricity prices in a perfectly competitive market).

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[1] *The permit allocation issue was not addressed, other than assuming that electricity prices are independent of allocation.*

The E-MARKAL modelling used, as its base case, NRCan's forecast for electricity demand to 2020 in an unconstrained environment (using a 7% discount rate). E-MARKAL was also used to develop a number of cost curves, based on different background assumptions that do not vary with the CO_2 emission constraint. This allowed the Table to assess the sensitivity of the model results with respect to certain key assumptions (*e.g.*, natural gas prices; electricity demand; the availability of new and refurbished nuclear plant; the cost of geological sequestration; etc.). Aside from producing cost curves, the model also provided information on a number of additional factors for each set of background assumptions:

- the relative cost to Canada of meeting the emission constraint.
- the prices for electricity that would apply in a perfectly competitive electricity market operating under the constraint; and
- the least-cost resource and technology mix (energy and capacity) given the constraint.
- E-MARKAL runs were conducted largely as single parameter variations on the assumptions of the NRCan base case.

There are a number of caveats to the use of the E-MARKAL model that have to be borne in mind when reviewing the results of the analysis. In particular:

- The most general assumption made by E-MARKAL is optimization – namely it produces least-cost solutions that may not occur in the real world for many reasons. E-MARKAL is therefore not a forecasting tool, since it does not take into account distortions that may exist in the Canadian electricity market. The use of a least-cost optimization model is therefore intended to inform policies that strive for least-cost solutions by estimating what those solutions would be.
- the E-MARKAL model, as noted earlier, isolates the electricity supply sector from the rest of the economy. In doing so, it does not take into account the impact on the Canadian electricity sector of changes in other economic sectors arising from a general emission constraint, such as:
  - changes in the absolute and relative prices of fossil fuels;
  - demand response to changes in the price;
  - demand changes in the U.S., and their impact on Canadian exports.
- The E-MARKAL model does not allocate gains and losses between different groups within the economy (*e.g.*, producers, taxpayers, investors, creditors, consumers etc.). Hence, it does not allocate "stranded costs" that could arise if facilities are rendered uneconomic.

Scenarios and Sensitivities

The Table developed a number of scenarios to test the sensitivity of the modelling results. These are described below and summarized in Table B-2:

- **No Bruce A:** the Bruce A nuclear units currently off-line are not returned to service, leaving 3,000 MW of non-GHG emitting energy out of the Ontario market. A 10% discount rate was used in the analysis;

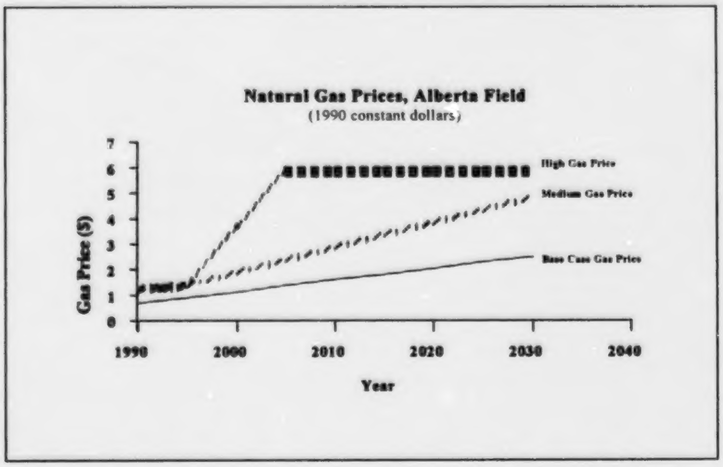
- **CO_2 Capture and Storage:** This was run in two scenarios, one assuming an unlimited aquifer storage potential at a cost of $38/tonne of CO_2 and the other assuming a lower $28/tonne cost applied to a somewhat more limited potential. In the latter case, the model assumed a potential for an additional 10 Mt of CO_2 to be used in enhanced oil recovery, thus lowering the net storage cost to $3/tonne CO_2. A 10% discount rate was used in both cases. The following table B-1 summarizes these assumptions:

Table B- 1

Capture and storage potential and cost assumed in two sequestration scenarios				
Storage Scenario	**Aquifer Storage Potential**	**Net Cost ($/tonne of CO2)**	**EOR Potential (Mt per year)**	**Net Cost ($/tonne of CO2)**
Base case	unlimited	$38	1.5	$13
Greater EOR	limited	$28	10	$3

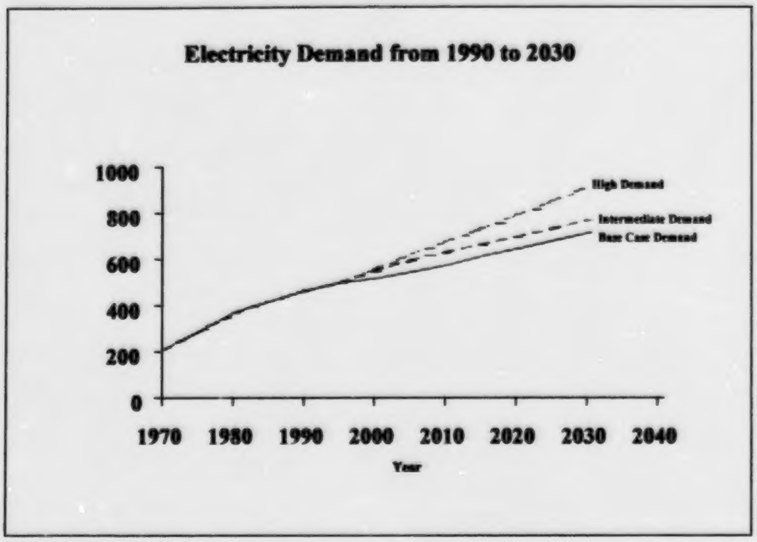
- **Higher gas prices**: the base case price had natural gas prices reaching $1.96/GJ by 2030, and most scenarios incorporated this assumption. However, the model also provided results under the assumption that natural gas prices would reach $6.00/GJ by 2004, then remain stable until 2030, and another (the "composite scenario", discussed below) based partly in gas prices rising linearly to reach $4.00/GJ by 2030. (All prices are in constant 1990 dollars). These gas price trajectories are shown in Figure B-1:

Figure B- 1



- **Higher Electricity:** a "high demand" case, based on utility projections, with a total generation of 722 TWh in 2010 and unconstrained emissions that are 38Mt higher than the base case. The high demand projection, as well as an intermediate demand prognosis used in the "composite scenario" discussed below, is shown graphically in Figure B-2:

Figure B- 2



- **No new hydro:** no new, large hydro projects are allowed in the forecast period.
- **A 4% Discount Rate Scenario:** the model used a discount rate of 4% p.a. rather than the 7% p.a. used in the other scenarios;
- **"Composite Scenario":** changed two variables (assumed intermediate growth in electricity demand and a medium increase in the price of natural gas to $4/GJ by 2030 – see Figures B-2 and B-3) rather than only one variable as in the other scenarios. This was done to examine the joint impacts of the levels of electricity demand and natural gas prices anticipated by many of the Table members.

Table B- 2

Electricity Table Modelling Assumptions

Demand Scenario	Runs Conducted	Parameter(s) (Changed in Runs Conducted)	Unchanged Parameter(s) (NRCan Base Case)
Low Demand NRCan Base Case	Base Case Required by Table Mandate	Not applicable	Discount Rate 7% Low Gas $1.96/GJ in 2030 Low Demand 644 TWh in 2010
	No New Hydro	No large scale hydro allowed to be built	Low Gas $1.96/GJ in 2030 Low Demand 644 TWh in 2010 Discount Rate 7 %
	No Bruce A	3,000 MW of nuclear capacity out of model Discount Rate 10%	Low Gas $1.96/GJ in 2030 Low Demand 644 TWh 2010
	High Gas	Gas rising to $ 6/GJ in 2005, then constant	Discount Rate 7% Low Demand 644 TWh in 2010
	Medium Gas	Gas rising to $4/GJ in 2020	Discount Rate 7% Low Demand 644 TWh in 2010
	Low Discount Rate	4 %	Low Demand 644 TWh in 2010 Low Gas $1.96/GJ in 2030
	High Discount Rate	10 %	Low Gas $1.96/GJ in 2030 Low Demand 644 TWh in 2010
	CO2 Capture and Storage	Limited and unlimited carbon disposal options in Western Canada	Low Gas $1.96/GJ in 2030 Low Demand 644 TWh 2010 Discount Rate 7%
Medium Demand	Moderately Higher Demand than NRCan	Demand reaches 671 TWh	Discount rate 7% Low Gas $1.96/GJ in 2030
	Composite Case (Combining medium demand & medium gas price)	Medium Demand 671 TWh Medium Gas (Rising to $4.00/GJ in 2020)	Discount Rate 7%
High Demand	Utility Forecasts of Expected Demand	Demand reaches 722 TWh in 2010	Discount Rate 7% Low Gas$1.96/GJ in 2030

The scenarios were run using a carbon dioxide emission constraint of 94% of 1990 levels. In addition, some of the scenarios were run using a carbon dioxide constraint of 80% of 1990 levels, in order to test for the existence of possible inflexion points in the emission reduction cost curve. Finally, a Kyoto-postponed model run was also performed to examine the cost impacts if a 94% of 1990 constraint was not imposed until 2020. The factors used to convert generation to CO_2 emissions in all cases are shown in Table B-3:

Table B- 3

Emission Rates for Technologies used in the Model

Technology	**Emission (Mt/PJ)**
Coal	
– Conventional Pulverized	0.271519
– IGCC - 2010	0.206313
– IGCC	0.231461
– IGCC - 2020	0.182493
Gas	
– CCGT Greenfield - 2010	0.106000
– CCGT Greenfield	0.111175
– CCGT Repowered	0.129556
– CCGT Cogen	0.083740
– SCGT Greenfield	0.174917
– SCGT Cogen	0.090500
– Micro Turbines	0.215386
– CCGT Greenfield - 2020	0.097167

Key Findings

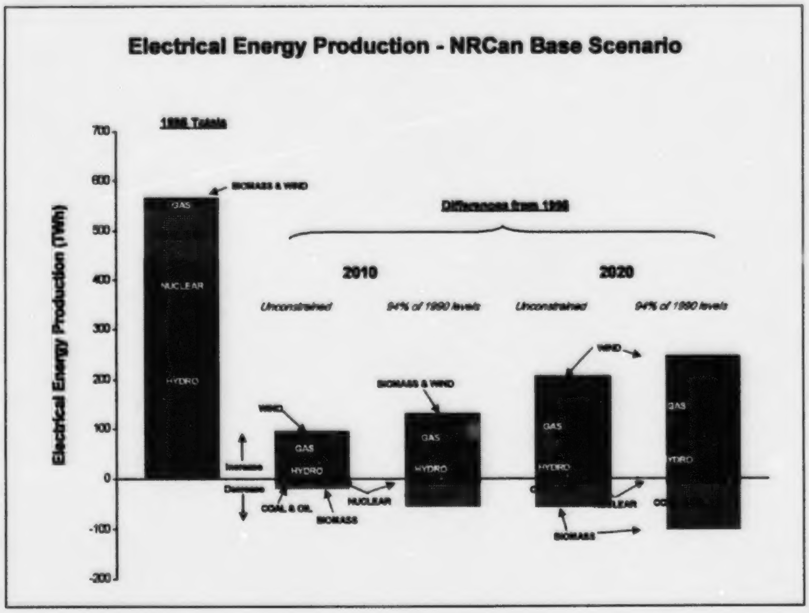
Unconstrained Base Case Forecast: In the base case ("NRCan") scenario, assuming no constraint, demand continues to grow, to 644 TWh, and CO_2 emissions increase to 118 Mt in 2010. However, the production mix changes. In particular, even without a GHG constraint, natural gas forms an increasing proportion of new capacity through 2020. Nuclear generation decreases slightly as plants are retired and not replaced on economic grounds. (In the base case and other scenarios, the model was prevented from bringing on new nuclear capacity until after 2020. This was to ensure consistency with the NRCan 2020 forecast which formed the basis of the Base Case, and which assumed no new nuclear plants would be built to 2020). Coal and oil generation also decreases at an accelerating rate, as plants are retired.

Impact of a 94% of 1990 Constraint:

A constraint of 94% of 1990 emissions (*i.e.* 90 Mt of CO_2, which is a 24% reduction from the unconstrained level of 118 Mt in the NRCan base case) increasingly favours low-GHG-emitting projects (*i.e.*, gas, hydro, and other renewables) over coal and oil generation. As shown in Figure B-3, compared to the unconstrained mix of generation, the constraint would, by 2010:

- increase natural gas generation by 22 TWh, with a shift within gas from steam and simple cycle gas turbines to combined cycle and cogeneration plants
- increase hydro by 9 TWh
- increase biomass by 4 TWh.
- decrease coal by 39 TWh
- decrease oil by 0.3 TWh.

Figure B- 3



In solving for a least-cost solution to the imposition of a GHG constraint, the model allows the mix of electricity generation and provincial impact to vary, positively affecting certain provinces and detrimentally others (unless there was a public-policy decision to redistribute the impacts). A 94% of 1990 constraint would, by 2010 result in:

- Manitoba, Ontario and Québec increasing their electricity output, no net change in Newfoundland and PEI, and a decrease in net TWh generated in all other provinces;
- gas substituting for coal primarily in Alberta and Ontario. The Ontario increase comes primarily from cogeneration, while that in Alberta from combined-cycle. This will increase demand for gas, and thus revenues for gas producers at the expense of the coal industry;
- building new hydro in Québec and Manitoba;
- inroads by other renewables in B.C. and Alberta;
- increased electricity exports to the U.S.A by Manitoba, Ontario and Québec decreased exports from other provinces.

These effects are summarized in Table B-4 below.

Table B- 4

Impact of a 94% of 1990 Constraint (TWh)

Technology	**BC**	**AB**	**SA**	**MB**	**ON**	**QC**	**NFL**	**NB**	**NS**	**PEI**
Hydro	0.0	0.0	0.0	6.5	0.0	2.32	0.0	0.0	0.0	
Nuclear					0.0	0.0		0.0		
Existing Coal		(22.7)	(0.61)		(9.23)			(3.68)	(1.45)	
Pulv. Coal										
IGCC										
Total Gas	(0.08)	6.65	0.0	0.0	14.09		0.0	1.36	0.21	
– *Gas*	*(0.08)*		*0.0*							
– *SCGT*							*(0.08)*			
– *Cogen.*	*0.0*	*0.0*	*0.0*	*0.0*	*14.09*		*0.08*	*0.0*	*0.0*	
– *CCGT*		*6.65*						*1.36*	*0.21*	
Oil								(0.28)	0.0	0.0
Wind		0.0				0.0				
Biomass	3.74	0.0			0.0					
Other		2.52								
TOTAL[2]	**3.66**	**(13.53)**	**(0.61)**	**6.5**	**4.86**	**2.32**	**0.0**	**(2.60)**	**(1.24)**	**0.0**
Inter-Prov Import	(4.79)	(0.19)	(0.33)	(0.17)	0.52	0.47		0.59	0.33	0
Inter-Prov Export		(5.24)	(0.03)	0.64	0.75	1.47	0.01	(0.29)	(0.87)	
Export to the U.S.	(1.28)	(7.89)	(0.88)	5.44	5.00	1.24		(1.62)		

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[2] *Since provincial demand is held constant, a reduction in total generation is matched by a mix of a reduction in exports to other provinces or the U.S., an increase in imports and a reduction in losses. Conversely for an increase in total provincial generation.*

The model analysis is carried forward to 2030 (*i.e.,* the constraint of 94% (or 80%) of 1990 is applied from 2010 to 2030). The impact on generation mix in 2020 is shown in Table B-5, and graphically in Figure B-4:

Table B- 5

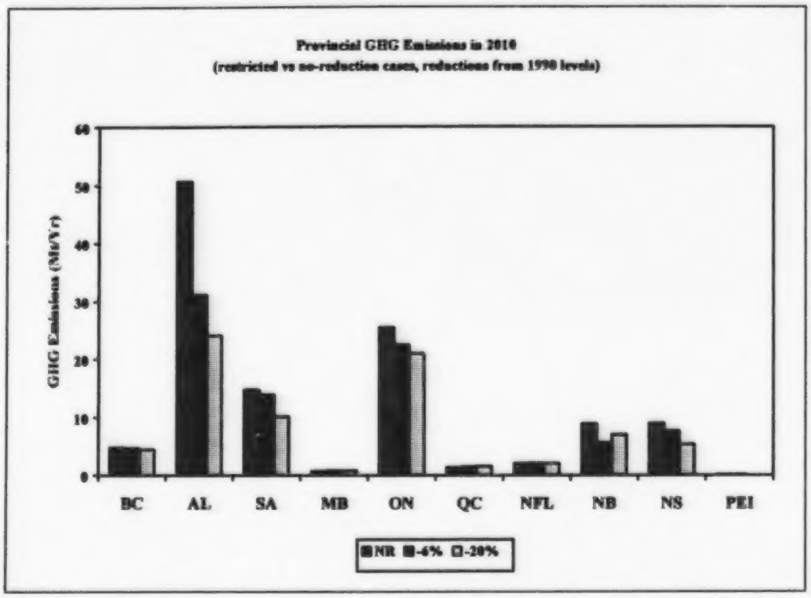
Change in generation mix from an unrestricted case to a constraint at 94% of 1990 emissions		
Technology	**2010 (TWh)**	**2020 (TWh)**
Hydro	+9	+28
Nuclear	0	0
Coal	-9	-45
Natural Gas	+22	+13
Oil	-0.3	0
Wind	0	+1.5
Biomass	+4	0

Thus, with a 94% constraint imposed in all periods, compared to unconstrained levels in 2020:

- hydro generation is 28 TWh higher;
- nuclear remains constant;
- coal-fired generation is 45 TWh lower;
- natural gas-fired generation is 13 TWh higher ;
- oil remains constant;
- wind power is 1.5 TWh higher;
- biomass remains constant.

Effects of Constraints on Emissions by Province: Because of their differing impacts on generation mix, inter-provincial electricity trade, and exports, a reduction in national emissions to 94% and 80% of 1990 levels will have different impacts on provincial emissions. These are shown in Figure B-4:

Figure B- 4

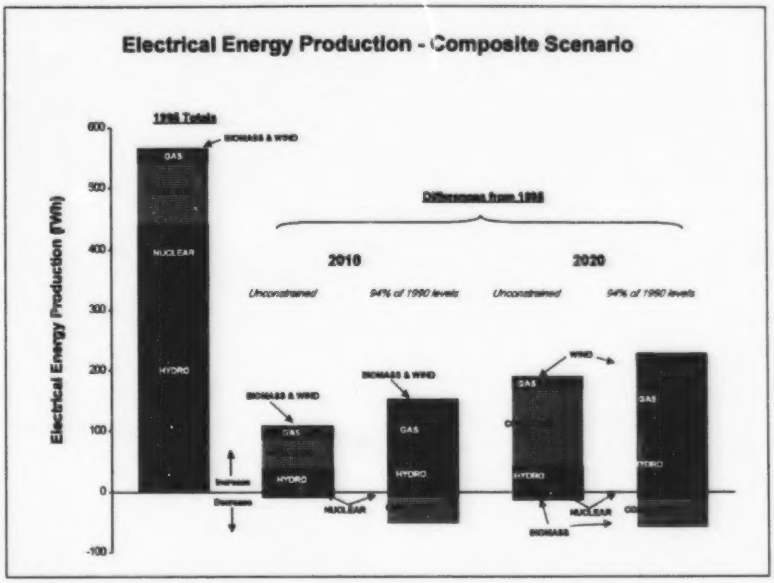


Relative to unconstrained emissions in the base case in 2010:

- For BC, emissions remain constant in the 94%, and 80% cases, at approximately 5 Mt/year;
- In Alberta, emissions drop from slightly over 50 Mt/yr. to approximately 30 Mt/yr. In the 94% case, and to approximately 25 Mt/yr. In the 80% case;
- Emissions drop marginally in Saskatchewan for the 94% case over the unrestricted forecast, to approximately 15 Mt/yr. An 80% constraint reduces Saskatchewan's emissions to approximately 11 Mt/year;
- Manitoba's, Québec's, Newfoundland's and PEI's emissions remain unchanged under all three scenarios;
- Ontario's emissions under a 94% constraint drop by approximately 3 Mt/year, to 22 Mt/year. An 80% constraint reduces Ontario's emissions by another 1 Mt/year.
- New Brunswick's emissions decrease by roughly 4 Mt/yr. under a 94% constraint, but only by about 2Mt/yr. in the 80% case;
- Nova Scotia's emissions under a 94% constraint drop by approximately 1 Mt/year. A constraint of 80% reduces Nova Scotia's emissions by an additional 1 Mt/year.

Impact of Scenarios: The above results represent a least-cost solution to emissions constraints of 94% and 80% of 1990 levels in 2010 under the assumption that no restrictions are placed on the types of generation allowed (*i.e.*, that the changes to the mix were the result of meeting the emissions constraints at the lowest cost to the utilities). In addition, the model derived impact estimates for the scenarios outlined in the *Scenarios and Sensitivities* section described earlier. In particular, the impact on the relative generation mix of the Composite Scenario – considered by some Table members as the more plausible base case - resulted in the changes shown in Figure B-5:

Figure B- 5



Under the Composite Scenario assumptions (intermediate electricity demand and medium gas prices), by 2010 in the unconstrained case:

- coal- and oil-fired generation increases in response to growing demand for electricity; in contrast, coal-and oil-fired generation decreased in the NRCan base case even in the absence of a constraint – see Figure B-3;
- gas-fired generation increases, much less than the base case due to higher gas prices; and,
- hydro increases slightly, while nuclear generation cannot compete in either scenario.

Thus, under Composite Scenario assumptions, the electricity generation sector starts from a higher capacity level under unconstrained conditions than it does in the NRCan base case. If a constraint of 94% of 1990 by 2010 is imposed:

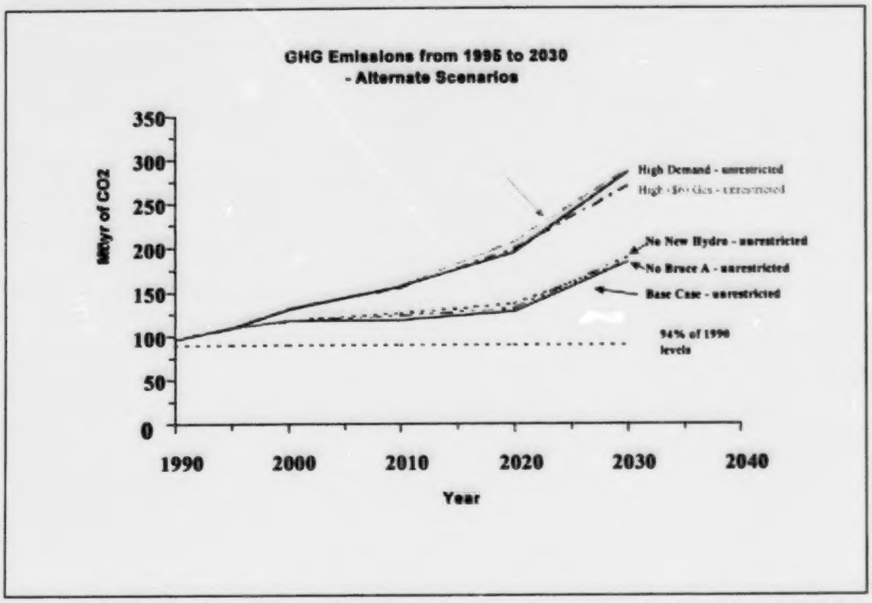
- coal- and oil-fired generation decrease by approximately 40 TWh, albeit from a higher base than under NRCan assumptions;
- hydro and gas-fired generation both increase significantly;
- the decrease in nuclear generation remains the same as in the unconstrained composite scenario case; and,
- biomass and wind-powered generation both increase market share.

Compared to the unconstrained case in the NRCan base scenario, the unconstrained case under Composite Scenario conditions results in higher initial capacity. The imposition of the constraint requires a larger decrease in emissions but because of the higher price of natural gas, the mix of generation has more coal and hydro generation than under the NRCan assumptions.

For2020, coal is even higher in the unconstrained case and thus there is a larger difference between the constrained and unconstrained composite alternative cases and between the NRCan base scenario and the composite alternative.

GHG Impacts: Projected unconstrained greenhouse gas emissions for the alternate scenarios are shown in Figure B-6:

Figure B- 6



- If no new, large hydro is allowed, the unconstrained emissions in 2010 would be 5 Mt higher than the base case reflecting the unavailability of this non-GHG emitting source. Meeting an emissions constraint requires a greater reliance on natural gas and the reduction of coal-fired generation is greater than in the base case;

- If the Bruce A nuclear plant does not return to service, the unconstrained emissions would be 6Mt higher than the base case in 2010. To meet the constraint, the increase in hydro and gas is greater, and the required decrease in coal is greater than in the base case;

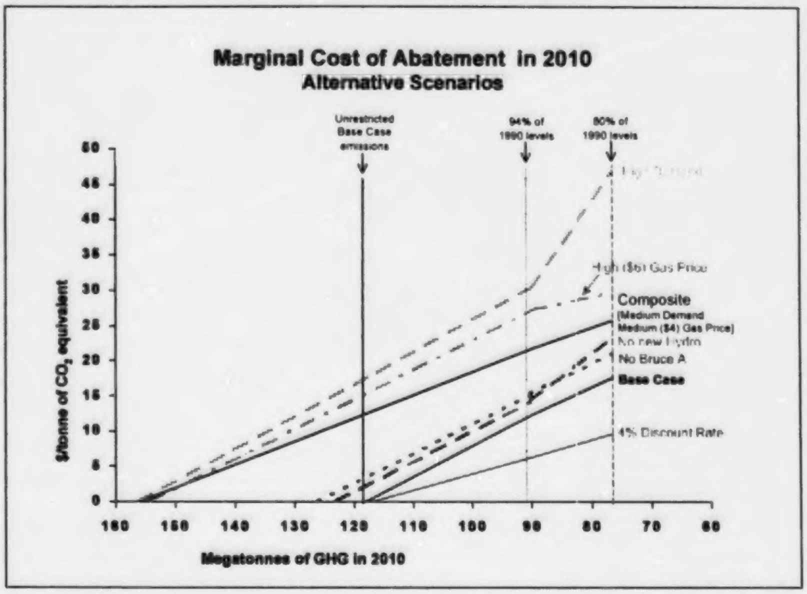
- If CO_2 capture and storage become available in sufficient volume, at low enough cost, then a much smaller reduction in coal is required to meet the constraint than in the base case, and coal-fired generation will form a larger part of the generation mix in provinces such as Alberta;

- A higher gas price results in more coal generation in the unconstrained situation, and therefore unconstrained emissions are 36Mt higher. The constraint is met with more coal, hydro and wind than in the base case because of the higher gas price;

- In the high demand case, with a total generation of 722 TWh and unconstrained emissions that are 38Mt higher than the base case in 2010, the unconstrained case has more hydro, coal and gas. The constraint is met with more natural gas, hydro, wind and biomass, and larger decreases in coal than in the base case. However, the constraint is met less with low-emitting natural gas, and more from non-emitting sources.

The marginal cost of abatement (*i.e.,* the incremental cost, in $ per tonne of CO_2 emissions reduced, of meeting a constraint under scenario conditions) was also calculated, and the results summarized in Figure B-7:

Figure B- 7



- Under the base case, the marginal cost of abatement rises relatively linearly throughout the range of emissions reductions, with a value of approximately $12/tonne for a 28 Mt reduction (i.e., 94% from 1990 levels) to $16/tonne for a 40 Mt reduction;
- The no new hydro case increases the marginal cost of abatement in 2010 to $14/tonne compared to $12/tonne in the base case. The no-hydro case diverges further from the base case in later years and at higher reduction levels;
- The No Bruce A case raises the marginal cost of abatement of a 94% constraint to approximately $15/tonne in 2010, reflecting the higher unrestricted emissions;
- As may be expected for such a capital-intensive industry, marginal abatement costs are very sensitive to the discount rate used. A 4% discount rate results in a marginal abatement cost of slightly over $5/tonne for a 94% constraint, and approximately $8/tonne for a 80% constraint, compared to $12tonne and $16/tonne respectively in the base case (using a 7% discount rate);
- The composite case increases the abatement cost to approximately $22/tonne in 2010 for a 94% constraint, and $25/tonne for a 80% constraint, reflecting higher unrestricted demand and a higher cost of gas;
- Raising the price of natural gas to $6/GJ appreciably raises the marginal abatement cost of meeting a 94% constraint, to over $25/tonne in 2010, and approximately $30/tonne for a 80% constraint;
- The high-demand case increases the marginal abatement cost the most - $30/tonne for a 94% constraint, and almost $48/tonne for an 80% constraint.

In all cases, the marginal cost of abatement is higher because in the alternative scenarios price of gas and demand for electricity are higher. In order to meet a constraint, therefore, electricity producers are forced to choose between higher-cost substitutes than under the base case.

Another view of the financial cost of abatement is to examine the net present value of the increased cost needed to achieve stabilization in 2030, at either the 94% or 80% levels, compared to the unrestricted base case. These costs are shown in Table B-6 and Figure B-8:

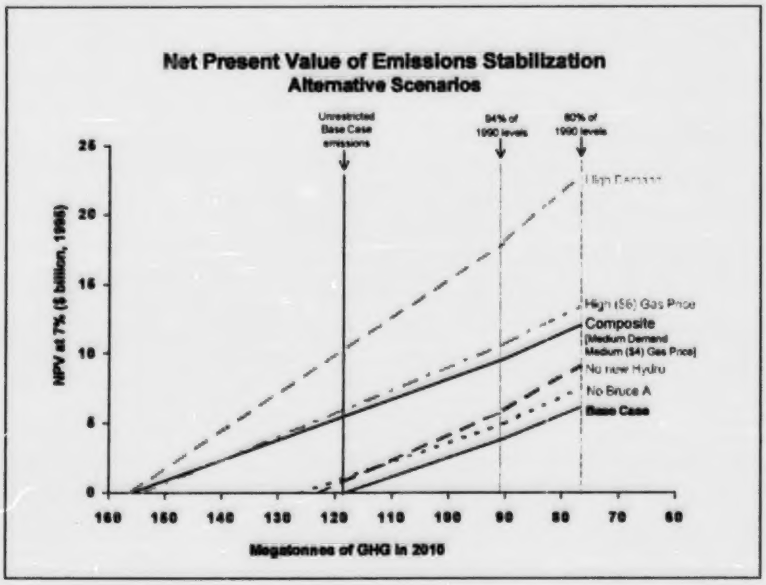
Table B- 6

Impact of Various Scenarios

Scenario	**Unconstrained Emissions in 2010 (Mt)**	**Cost of Stabilization at 94% of 1990 emissions (NPV - $ billion)**	**Marginal Abatement Cost in 2010 ($/tonne of CO2 equivalent)**
Base Case	118	3.9	12.19
No New Hydro	123	5.9	14.34
No Bruce A	126	5.0	15.33
High Demand	156	18.0	30.48
Composite	156	9.6	21.70
High ($6) Gas Price	154	10.7	27.28
4% Discount Rate	117	5.7	6.28

As Table B-10 shows, meeting a stabilization goal of 94% of 1990 emission levels would require an incremental investment of almost $10 billion, in net present value terms, for the composite case, which is considered most likely by the industry. A high gas price scenario would require $11 billion in the present value of capital and operating costs, and stabilization under the high-demand case would cost $18 billion. (A discount rate of 7% p.a. was used for this comparison).

Figure B- 8



Impacts of Preparatory Measures:

The model was also used to estimate the impacts of two of the preparatory measures suggested by the Table, *i.e.,* financial support for emerging, non-emitting technologies and increasing coal royalties.

- Financial support for emerging, non-emitting technologies: the E-MARKAL model was run to estimate the impact of production credits of 1 cent and 2.5 cents per kWh. The 1-cent credit reduced emissions by 1.4 MT CO_2 in 2010 (i.e., 5% of the total 28 MT required to be reduced in a 94% constrained case), while the 2.5-cent credit reduced emissions by 2.3 MT (i.e., 8% of 28 MT) in that year. The one-cent credit moved about 4,700 GWh out of large hydro and gas and put it into wind and microturbines run on flare gas. The 2.5-cent credit moved about 6,500 GWh from gas, large hydro and coal into wind and microturbines run on Alberta flare gas. Depending on subsidy level, a net benefit to the industry of $150 – 560 million (present value over 30 years) was more than offset by government expenditures of $257 – 877 million, for net total costs to the economy (relative to a no-reduction case) of $107 – 317 million. The marginal abatement costs for this measure were estimated at $7.18-$13.70/tonne in 2010.
- **Coal royalty increase:** The model simulated this measure by adding a 10-fold coal royalty increase to the cost of production of coal-fired electricity, thus equating coal royalties to the level imposed on natural gas on a per-kWh-of-electricity-produced basis. It assumed that the full increase would be passed on in each province but Ontario, where it would have no effect due to the availability of and reliance on imported coal in Ontario. Under these assumptions the cost of coal-fired electricity went up about 0.25 cents/kWh outside of Ontario. This was not enough to induce coal-to-gas substitution in the model, and thus emissions are not reduced by this measure.

Figure B- 9

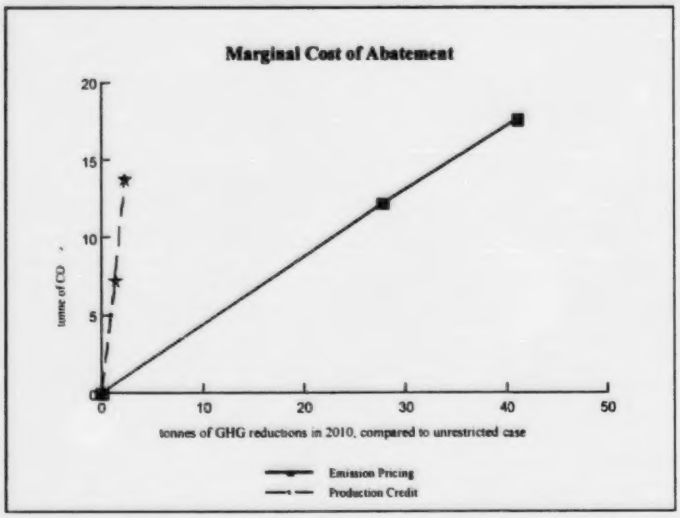


Figure B-9 shows that the production credit measure is much less effective in reducing emissions in terms of dollars expended per tonne of reductions than is emission pricing. The coal royalty increase measure is not shown, as it had no impact on emissions. While the financial support for emerging technologies (modelled in the form of a production credit) would result in higher abatement costs than emission pricing, its purpose as a preparatory measure is to position the sector for lower cost emission reductions in the later, commitment period.

Impact of Large Generation Portfolio Standard

The Table also modelled two variations of a large portfolio standard designed to achieve Kyoto-like reductions through a requirement that 3% of total demand in 2005 and 5% in 2010 be met from emerging, non-GHG-emitting sources.

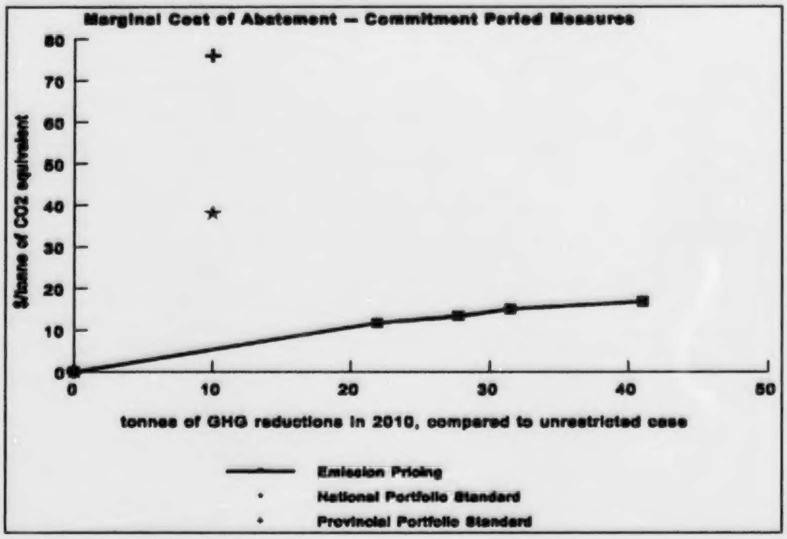
In the first version of this measure, it was assumed that each province applied the standard individually.

Under these conditions, the measure reduced emissions by about 10 MT in 2010, at a cost of approximately $8 billion over 30 years, at a marginal cost of approximately $75/tonne. It did so by introducing wind, solar, geothermal and reducing the share of natural gas and to a lesser extent large hydro.

The second version, a national portfolio standard, allowed the standard to be met nationally. This approach is more economically efficient, since the cost of meeting the standard is significantly less if the changes take place in the provinces where they cost the least. Under these conditions, the cost of the measure was cut in half, $4.2 billion over 30 years. The marginal cost of abatement was $41.60/tonne, close to the assumed unit cost for CO_2 capture and storage using current technology.

The abatement costs of these measures are compared to the least-cost (marginal abatement cost) in Figure B-10:

Figure B- 10



The point of these results is that the greater the deviation of a regulatory solution to meeting an emission constraint from the cost minimizing mix of generation that would result under emission pricing, the higher the cost in meeting the constraint.

ANNEX C. OTHER ENVIRONMENTAL IMPACTS[1]

Introduction

The purpose of this report is to document the factors related to environmental and health impacts associated with the different options considered by the Electricity Table to reduce greenhouse gas emissions in the electricity sector. It is part of a broader effort to understand the impacts, costs and benefits of the different electricity sector options.

A range of options was considered by the Electricity Table, but they generally have similar major supply effects. Specifically, relative to a "no restrictions" scenario:

- coal-fired thermal output declines;
- natural gas-fired combined cycle thermal capacity and output increase;
- hydro capacity and output increase;
- wind and biomass capacity and output increase; and
- transmission line developments and inter-provincial trade are affected.

In some scenarios, carbon sequestering in coal plants is increased, with associated pipeline and other developments. Oil-fired thermal output, which is limited in any event, declines. Nuclear capacity is not generally affected by the options, at least in the short to medium term.

There are significant differences among the options, and differences in their impact depending on the set of assumptions one makes about demand, prices, technology and other relevant factors. However, for the most part those differences affect the magnitude of the electricity output and capacity changes listed above, not their general direction.

Accordingly, the first step taken in this study is to document the environmental and health-related impacts associated with each technology affected by the options (i.e., decreases in coal output; increases in gas combined cycle, hydro, wind and biomass capacity and output, changes in transmission line developments). Then, for a selected set of options where the magnitude of the changes are estimated for each technology, the magnitude or nature and significance of the total impacts are documented and, where possible, aggregated, to describe the option's overall effects.

The report draws on information compiled for the Electricity Table and government and industry data on the various technologies that are affected by the options. Specifically the following sources were used:

- Environment Canada (confidential) thermal plant emission factor data;
- Alberta and Saskatchewan government reports on full fuel-cycle impacts;
- Atmospheric Science Expert Panel Report on secondary particulate impacts;
- BC Hydro, SaskPower, Manitoba Hydro and Hydro Quebec on hydro development impacts;
- Electricity Table and other consultant reports on thermal, wind and transmission development characteristics.

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[1] *Study prepared for the Electricity Table of the National Climate Change Process by Marvin Shaffer &Associates Ltd. and Alchemy Consulting Inc., June 1, 1999 The Table's schedule did not permit discussion or adoption of these findings.*

It is important to recognize that the information available from these sources, as well as the nature and scope of this study, permit only an overview of the environmental and health-related impacts of the electricity sector options. Not all of the options can be modelled or otherwise analyzed to determine what the precise electrical generation and new development changes will be. Even where such changes can be estimated, so many plants and developments are affected that environmental impacts can only be outlined at a high level. Site-specific data are not always available, new project design and mitigation strategies have not in all cases been developed and, in any event, would be too time consuming and costly to compile within the scope of the study.

The objective of the assessment is to identify the major impact issues of potential interest or concern; to outline the nature and factors governing the importance of these impacts; and to document or describe what is known about them, including quantitative impact estimates where data allow.

AMG Guide for the Analysis of Environmental and Health Impacts

The Analysis and Modelling Group developed a guide for the analysis of environmental and health impacts to facilitate the inclusion of environmental and health impacts in the roll-up analysis of options put forward by the Tables.[2]

The guide calls for an identification of the key issues with respect to impacts on the atmospheric environment, aquatic environment, terrestrial environmental and social and human health conditions. For each of the key issues, (i) the scope and nature of effects; (ii) mitigation potential; (iii) stakeholder concerns; and (iv) uncertainties are to be identified and assessed. Quantitative effects are to be reported in physical units, where appropriate, separate from any valuation, to facilitate consistent overall valuations during the roll-up phase.

Concerns were expressed by Electricity Table members that the AMG guide is too overreaching, requiring a comprehensive assessment that would be difficult to do and potentially unreliable or misleading given the time frame for the analyses and the varying states of knowledge of the projects that could be affected by the options.

Whether the AMG intended such a comprehensive evaluation or not, it is clear that any assessment of environmental and health impacts of Electricity Table options at this time must be recognized as high level and preliminary, particularly with respect to new project developments, where projects have not been fully defined and detailed environmental impact studies have not been completed. Even the more quantifiable air emission impacts must be recognized as only indicative of an effect, since specific consequences can only be determined in much more detailed site specific contexts and analyses.

Multiple Account Framework

- Multiple account analysis is an extension of benefit-cost analysis. However, whereas benefit-cost analysis attempts to monetize all effects and determine a single indicator of overall net benefit, multiple account analysis recognizes that not all impacts can be reliably monetized, nor are they equally understood, and it can be misleading to aggregate the different types of impacts into one overall measure. Different types of impacts can be separately identified and assessed in qualitative, physical quantitative and in some cases monetary terms. That will not permit an aggregation of overall effect, as in benefit-cost analysis, but will facilitate a clear understanding of the relative advantages, trade-offs and issues involved.
- A multiple account framework is well-suited for this impact assessment. It is consistent with the intent of the AMG guide, yet can accommodate and clearly recognize the markedly different nature and state of knowledge of the different technology output and new capacity impacts and effects.
- The categories of impact (the environmental and health evaluation accounts) should in principle address the full range atmospheric, aquatic, terrestrial and social/human health-related changes listed in the AMG guide. However, in recognition of the overview nature of this assessment and to facilitate an identification of the major impact issues, a simpler framework is used in this study. Four impact categories or accounts are used:
  - Air emissions

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[2] *AMG, "Guide for the Assessment of Environmental and Health Impacts", February 16, 1999.*

  - Flooding and other land requirements
  - Water flow and water quality
  - Community impacts and quality of life

- Environmental and health-related impacts will arise because of changes in the mix of electricity production, by type and location of plant, and because of changes in the amount and type of new generation and transmission capacity that is developed. The air emissions account addresses the impacts of major interest or concern associated with changes in the mix of electricity production. The other three accounts address impacts of major interest or concern associated primarily with new generation and transmission developments. Only very broad indicators are documented in these accounts (e.g., quantity of land flooded and alienated by new projects, nature of resource and resource use effects, impacts on traditional and community activities, infrastructure and other community effects). As noted earlier, it is beyond the scope of this study to document detailed impacts of each of the projects advanced or deferred as a result of greenhouse gas reduction strategies.

Air Emission Account

- Air emissions of general interest and concern include:

  (i) criteria or common air contaminants – nitrogen oxides (NO_x), sulphur dioxide (SO_2), particulate matter (PM and its smaller size fractions PM_{10} and $PM_{2.5}$), carbon monoxide (CO), and volatile organic compounds (VOC);

  (ii) hazardous air pollutants (HAPs) – a large group of pollutants designated toxic under the *Canadian Environmental Protection Act* or listed as a hazardous air pollutant under section 112 of the *U.S. Clean Air Act*, and

  (iii) greenhouse gases.

- For purposes of this study, impacts of the electricity sector on emissions of CO are not considered material and impacts on greenhouse gases are not a differentiating variable, since the options specify what reductions are required. While ambient CO levels are generally of concern in central urban locations, the primary source is motor vehicle emissions. Thermal power generation produces some CO, but not generally as to cause unacceptable ambient concentrations in the vicinity of the plants, nor to contribute to elevated levels in urban areas. For these reasons, CO is not generally identified as a concern with respect to power generation.

  Thermal electrical generation emits insignificant amounts of chemically reactive or toxic VOCs, so this class of pollutants is not considered to be important for the purposes of this study.

  Since electrical power generation does not produce appreciable quantities of VOCs, any hazardous components of the VOC class from the electricity sector are also unimportant for the purposes of this assessment. Some metallic element and compound components of PM, however, are emitted by power generation facilities and are of concern with respect to long range transport and deposition on regional and continental scales. Constituents of thermal power generation emissions (primarily coal- and oil-fired) such as mercury, arsenic and vanadium have been the subjects of impact assessments over the years. Although the individual elements and compounds may have toxic effects on ecosystems, the importance for damage valuation purposes of the contributions from thermal power generation is difficult to assess. There is insufficient information both on emissions from individual facilities in each province and on their potential contribution to environmental damage to include particulate HAPs explicitly in this analysis. For these reasons, particulate HAPs have been excluded for the purposes of this assessment. This should not be taken as an assessment of their potential environmental importance in a broader context. Ongoing North American assessments emphasize mercury emissions in this regard.

- The air emissions that are important, then, for thermal power production and that are documented in this study are impacts on emissions of nitrogen oxides (NO_x), sulphur dioxide (SO_2), and particulates (PM, PM_{10}, $PM_{2.5}$). The nature of these contaminants and the concerns they raise are outlined below.
  - ***Nitrogen oxides (NO_x):* - NO_X** includes the two forms: nitric oxide (NO) and nitrogen dioxide (NO_2). It does not include the greenhouse gas, nitrous oxide (N_2O). NO_2 is known to have direct impacts on human respiratory health, but the association with health impacts at typical ambient air concentrations is weaker than for PM, ozone or SO_2. Until recently, it has not been generally considered to be associated with increased human mortality, although some studies have found an association between NO_2 exposure and mortality (including a Health Canada study of Canadian cities).

    The major concern for NO_X emissions is their participation with chemically reactive VOCs as precursors of ground level ozone formation through atmospheric chemical reactions (on warm, sunny days). Some of the emitted NO_X is further converted in the atmosphere into nitric acid (as well as many other similar compounds). Nitric acid reacts primarily with ammonia in air to form particulate ammonium nitrate, which is found in the fine fraction of PM (i.e., $PM_{2.5}$). Thus, NO_X emissions are also of concern as precursors of $PM_{2.5}$. Nitrates contribute to acidic deposition in some areas of Canada where long-range transport of air pollutants is significant—primarily from Manitoba eastward.

    The participation of NO_X in reactions to form ozone or $PM_{2.5}$ depends strongly on whether the necessary atmospheric conditions exist in the region through which the emissions are transported by airmass movement. As a rule of thumb, the secondary reactions of NO_X will be significant in regions of Canada that are currently experiencing elevated levels of ozone or secondary nitrates, or in which acid rain is a demonstrated problem.

    Until recently, ozone has been a concern primarily respecting human respiratory illness and vegetation damage (including crops) in certain regions of Canada (the Lower Fraser Valley of BC, the Windsor-Quebec City corridor in Ontario and Quebec and the southern Atlantic Provinces). The current Science Assessment Document for Ozone in the Canada-Wide Standards development process, however, identifies possible association of ozone with elevated human mortality, as well.[3]

    NO_X emissions are important in thermal electrical power generation for the above environmental and health reasons and therefore are considered important in this assessment.
  - ***Sulphur dioxide (SO_2):* - SO_2** is known to cause direct human respiratory health effects, but at current ambient air levels in Canada, the association is generally weak.

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[3] Ground-level Ozone. Science Assessment Document Summary, Consultation Draft. *Federal-Provincial Working Group on Air Quality Objectives and Guidelines, March 1999.*

SO_2 is generally considered principally in relation to morbidity (illness) rather than mortality (life-shortening). However, an association between SO_2 exposure and human mortality has been demonstrated in some studies. Similarly to NO_X, some emitted SO_2 is transformed in the atmosphere into sulphuric acid, which in turn reacts with ammonia to form particulate sulphates in the $PM_{2.5}$ fraction. Long range transport and deposition of sulphates also typically dominate acidification of precipitation. Sulphuric acid reacts much faster than nitric acid in competition for available ammonia, so as sulphur emissions are reduced across Canada, more ammonia is available to react with nitric acid, increasing the formation of nitrates.

SO_2 is important in emissions from coal- and oil-fired thermal power generation, and based on the above rationale, is considered important in this assessment.

- ***Particulate matter (PM, PM_{10}, $PM_{2.5}$):*** **- In** recent years, the finer fractions of PM (i.e., PM_{10} and $PM_{2.5}$) have been shown to have a very significant association with human morbidity and mortality. Ambient levels of PM_{10} are strongly associated with increased human mortality (generally, and especially from respiratory and cardio-vascular illness). Most air pollution health scientists believe that fine PM (i.e., $PM_{2.5}$ or smaller, which is a sub-fraction of PM_{10}) is the most important factor in the observed association between exposure to PM in ambient air and life-shortening. Both direct source emissions and indirect or secondary formation of PM_{10} and $PM_{2.5}$ contribute to ambient levels.

  In economic evaluations of air pollution damage that have been carried out in recent years,[4] PM has dominated the contributions of ozone and directly-emitted NO_X and SO_2 effects to estimated damage costs, primarily because of the association of PM with human mortality. The high value attributed to PM damage results from the high value placed on a shortened human life in these studies. Verification of recent suggestions that ozone, SO_2 and NO_2 are independently associated with human mortality would increase their contribution to health damage valuation. Any pollutant that is shown to contribute significantly to human life shortening will contribute materially to a high damage cost compared with those pollutants that are associated with human morbidity only.

  Direct (primary) PM emissions and emissions of precursors of secondary PM formation are both associated with thermal power generation (principally coal- and oil-fired); therefore, PM is a pollutant of concern in this study. Combustion (as opposed to fugitive) emissions from electrical power generation facilities will generally be in the PM_{10} fraction (generally, these will be $PM_{2.5}$ and smaller). For purposes of this assessment, changes in primary PM emissions are assumed to be PM_{10}. Changes in secondary PM emissions are assumed to be $PM_{2.5}$.

Evaluation Methodology: - For purposes of indicating the magnitude of the NO_x, SO_2 and PM impacts, the change in the tonnes of these emissions are calculated. Primary emissions impacts are calculated by multiplying provincial average existing and new plant emission coefficients for each technology, by estimated changes in output of existing and new thermal plants. The relative importance of the resulting emission changes is then indicated by reference to the 1995 National Emission Inventory for each pollutant (by province) – see Appendix A. Secondary emission impacts are calculated by applying approximate annual percentage conversion factors developed recently for the Joint Industry/Government Study on Sulphur in Gasoline and Diesel Fuels.[5] The following conversion rates for SO_2 to particulate sulphate (in the form of ammonium sulphate) were used in that study. The corresponding conversion rates for NO_X to particulate nitrate (as ammonium nitrate) are estimated to be about one-third of the corresponding SO_2 rates.

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[4] *See, for example,* Economic Analysis of Air Quality Improvement in the Lower Fraser Valley (Volume 1: Main Report), *BOVAR-Concord Environmental, November 1995;* Health and Environmental Impact Assessment Panel Report, *Joint Industry/Government Study, Sulphur in Gasoline and Diesel Fuels, June 1997 (updated April 1998);* The Benefits and Costs of the Clean Air Act, 1970 to 1990, *US Environmental Protection Agency, November 1997.*

These urban region factors can be assumed for the purposes of this study to be surrogates for their respective provinces and provinces with similar characteristics.

Table C- 1

Secondary Chemical Conversion Rates for SO_2 and NO_X

	Annual Average Chemical Conversion Rates	
Urban Region	**[SO_2 => $(NH_4)_2SO_4$, %/year]**	**[Approx. NO_X => NH_4NO_3, %/year]**
Vancouver	1.6	0.5
Edmonton	0.94	0.3
Winnipeg	0.15	0.05
Toronto	5.0	1.7
Montreal	2.8	0.9
Saint John	2.4	0.8
Halifax	4.2	1.4

The primary and secondary emission impacts, as calculated above, include those within the electricity sector. For purposes of illustrating full fuel cycle effects, emission coefficients for upstream production, processing and transport are applied and reported separately.

The importance of the change in the magnitude of emissions varies by type of pollutant and location of emissions. Generally, emissions, like PM, that are strongly associated with increased mortality, are of far greater importance than others. Recent damage cost estimates for PM have been estimated as 100 to 1000 times greater on a tonne for tonne basis than for NO_x and SO_2. If gaseous ozone, NO_2 and SO_2 become more strongly implicated in human mortality than previously, as suggested by some studies, this would change.

The frequency of health impacts, however, depends very much on location. Proximity to dense, large populations is critical as that determines the number of persons exposed and, therefore, expected number of cases of illness or premature death. Thus, generally speaking, the population impacts of the emission changes vary greatly for urban and rural locations. BC Hydro, for example, for its social costing purposes, values rural emissions at one-tenth those in urban areas.[6] The basis for this is the exposed population. The impacts of secondary products of emissions may in fact be more severe in rural areas than urban because of atmospheric transport effects.

The regional formation of ground-level ozone and secondary PM that may impact human populations depends on emissions occurring in regions in which atmospheric conditions favour the chemistry necessary for these processes. Thus, impacts of emissions that lead to formation of secondary pollutants are considered to be most important for the purposes of this study in those regions of Canada that are currently considered to be critical under the federal smog management program: the Lower Fraser Valley of BC, the Windsor-Quebec

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[5] Atmospheric Science Expert Panel Report. *Joint Industry/Government Study: Sulphur in Gasoline and Diesel Fuels, August 14, 1997.*

[6] *BC Hydro, Resource Acquisition Policy, 1994.*

City corridor in Ontario and Quebec and the southern portion of the Atlantic Provinces (NB & NS).

The effects of long-range transport of air pollutants (LRTAP) depend both on the chemistry of the atmosphere in which the pollutants are being transported and on the sensitivity of the ecosystem receptors. Since the chemistry of LRTAP also produces secondary fine particles in the $PM_{2.5}$ fraction, regional and continental transport also effects human health. In Canada, LRTAP is generally considered to be most important from Manitoba eastward.

Table C-2

Air Emission Account Summary

Indicators	Concern	Importance
NO_x (tonnes)	Respiratory health Visibility Ozone precursor Acidic deposition (LRTAP) Precursor of $PM_{2.5}$	Greatest in urban regions currently deemed critical under federal smog management program LRTAP greatest Manitoba eastward
SO_2 (tonnes)	Respiratory health Visibility Acidic deposition (LRTAP) Precursor of PM2.5	Greatest in urban areas LRTAP greatest Manitoba eastward Potential forest impacts
PM, $PM_{2.5}$, PM_{10} (primary and secondary tonnes)	Respiratory health and mortality Visibility	Greatest in urban areas

Other Evaluation Accounts

The development and operation of new hydro, gas turbine, wind, biomass and transmission facilities have a wide range of potential environmental effects.

For hydro developments, impacts related to flooding and water flows tend to dominate. Flooding and water flow changes can affect fisheries and aquatic resources, forestry, agriculture, wildlife, recreational and tourism opportunities and archaeological sites. These resource impacts in turn can affect the people and communities who depend on them for traditional, commercial and recreational purposes. Communities can as well be directly affected through displacement, construction-related and other development effects.

For all types of developments, significant impacts can arise from the land required both for the project site and for related rights-of-way (e.g., for roads or transmission). The alienation of land for project purposes can directly diminish or affect resources and related activities, depending on the nature of the land involved. In the case of new rights-of-way there can also be effects on adjacent lands and resources due to changes in access, particularly in the remote areas.

There are other impacts that can arise from new projects, related for example, to waste management, water discharges, noise and other aspects of operations. Generally, however, these are managed within acceptable limits, without significant residual environmental concern.

As noted earlier, to highlight the major impacts three evaluation accounts are used: (i) flooding and other land requirements; (ii) water flow and water quality; and (iii) community impacts and quality of life.

The primary indicator of impact in the flooding and land account is the amount of land affected (hectares or, in the case of rights-of-way, kilometers). The nature and significance of those impacts depend on how resources and resource use are affected. Summary information on that is provided where available.

Impacts under the water flow and water quality accounts are documented only in qualitative terms, summarizing in particular effects on fisheries resources. Similarly impacts under the community account are documented in qualitative terms, indicating the major areas of interest or concern that have been identified. Again, the overview and preliminary nature of the evaluation must be emphasized. The ultimate impacts will depend on project design, mitigation and implementation strategies, which, for many of the projects affected by the options, have not been determined:

Table C- 3

Other Evaluation Accounts

	Indicators	**Concern**	**Importance**
Flooding and Land Requirements	Hectares Km for rights-of-way	Impacts on resources and resource use	Depends on current land use, resource characteristics and nature and magnitude of effects
Water Flow and Quality	Qualitative	Fisheries resources and use	Depends on resource characteristics and nature and magnitude of effects
Community	Qualitative	Traditional and commercial activities Infrastructure and services Displacement	Depends on resource impacts, community characteristics and project design, mitigation and implementation

Impact Assessments

Thermal Plants

Air Emissions

In Table C-4, estimated emission coefficients for existing fossil and biomass-fired generation plants are shown by province and fuel. The provincial estimates reflect weighted averages for the different plants within each province. The estimates are based on an Environment Canada confidential emission factor database for 1995, private communications and other sources as noted in the table.

As shown in the table, the principal emission impacts, most notably for SO_2 and PM, are from coal and oil-fired plants. For coal-fired plants, the NO_x emission factors are very similar from province to province, but the SO_2 and PM emission factors reflect differences in fuel composition and control technology across the country.

The table shows only direct, primary stack emission factors. Upstream fuel emissions are discussed below. Formation of secondary pollutants from NO_x and SO_2 (i.e., nitrates and sulphates) is handled by using estimated conversion rates specific to each province. The results of estimating quantities of secondary particulate matter are discussed in the next chapter.

The abbreviations in Table 1 for the various technologies are as follows:

SSC = simple steam cycle (steam boilers)

SCGT = simple cycle gas turbine (no steam cycle unit)

CCGT = combined cycle gas turbine (with integral steam cycle unit)[7]

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[7] *Emission rates of common pollutants from CCGT and CCGT with cogeneration (CCGT/cogen) are considered to be equal for the purposes of this study.*

Table C- 4

Stack Exhaust Emission Factors for Existing Fossil and Biomass-fired Generation Plants by Province and Technology (kg/MWh)[1]

Province	Coal (conventional)[5]			Gas (SSC)			Gas (SCGT)			Gas (CCGT), SCR or LoNOx			Oil			Biomass		
	NO_x	SO_2	PM	NO_x	SO_2	PM	NO_x	SO_2	PM	NO_x	SO_2	PM	NO_x	SO_2	PM	NO_x	SO_2	PM
B.C.[2]	NA	NA	NA	0.07	0.002	0.02	0.4	0.002	0.02	0.4	0.002	0.02				3.1	0.14	0.58
Alberta[3]	2.1	3.7	0.22	0.95	0.004	0.02				0.4	0.002	0.02						
Saskatchewan[4]	3.6	8.8	4.5	0.7	0	0.01												
Manitoba	3.2	5.9	7.7															
Ontario[6]	2.5	4	0.29										1.2	1.9	0.01	3.1	0.14	0.58
Quebec																		
New Brunswick	2.1	7.8	0.1										2.7	12.7	0.1			
Nova Scotia	3.1	18	0.24										1.6	9.9	0.22			
Nfld. & Lab.													1.9	9.7	0.78			
PEI[7]													2.1	10.8	0.37			

(a) Data from current Environment Canada emission factor database for 1995, G. Ross & D. Rose, private communication, unless otherwise noted.
(b) Some data taken from recent assessments of recently commissioned or under-construction plants
(c) Most values form "Fuel Cycle Emissions Analysis … in Alberta, Canada" (Alberta DOE, et al., 1997)
(d) Some data from "Levelized Cost and Full Fuel-Cycle Environmental Impacts of Saskatchewan's Electric Supply Options" (Sask. Energy Conserv. & Dev. Authority, 1994), as quoted in Alberta DOE, 1997.
(e) Bituminous, sub-bituminous, lignite depending on the dominate fuel in the province.
(f) Biomass factors assumed the same as B.C.
(g) Average NB/NS/NF oil values

In Table C-5, estimated emission coefficients for new gas and biomass generation plants are shown. They reflect direct stack exhaust emissions only. As well, no credit is given for any displaced fossil fuel use in cogeneration facilities, since this has to be determined on a site-specific basis.

Table C- 5

Emission Factors for New Gas and Biomass-fired Generation Plants (Kg/MWh)

Technology***	NO_x	SO_2	PM	Applicable Provinces*
CCGT/SCR or adv. LoNox**	0.034	0.002	0.01	BC, ON, NB, NS
CCGT/LoNOx+ (SCGT)	0.11 same	0.002 same	0.01 same	AB, SA
IGCC+++	0.18	0.01	0.02	Any in which new advanced coal facilities appear
Biomass++	3.1	0.14	0.58	BC, ON

*According to whether province is in a current NAAQO non-attainment area.
**BC Hydro Power Supply Engineering, Current Suppliers' specification for equipment to be installed after 2000
*** Emissions are assumed to be the same for CCGT and CCGT/cogen
+Full Fuel Cycle Emissions Analysis of Existing and Future Electric Power Generation Options in Alberta, Canada, Alberta Department of Energy and a consortium of energy sector stakeholders representing all of major fossil fuels and wind energy, undated (ca. 1997).
++Woodwaste biomass emissions factors are assumed not to change between now and 2010.
+++ Integrated coal gasification, combined cycle ("advanced coal technology"). Current MARKAL modelling scenarios do not identify new advanced coal technology facilities, but they may appear in subsequent scenarios. The emission factors are included here for completeness.

Table C-6 shows typical upstream emissions of NO_x and SO_2 for Alberta coal and natural gas-fired facilities. One could expect somewhat higher emissions of, in particular NO_x, for gas plants in other provinces because of greater transportation-related fuel use. The estimates are based on a full fuel cycle report by the Alberta Department of Energy.

The upstream impacts for coal are very small, accounting for some 1% of the typical full cycle NO_x emissions for coal and less than 0.1% of the typical full cycle SO_2 emissions. For gas, the upstream NO_x and SO_2 emissions are important – typically accounting for one-third of the full cycle NO_x for a single cycle plant (over 50% for combined cycle) and almost all of the full cycle SO_2 emissions.

Table C- 6

Upstream NO_x and SO_2 Emission Factors (Kg/MWh)*

	NO_x	SO_2
Coal	0.03	0.005
Gas	0.44	0.65

* ***Full Fuel Cycle Emissions Analysis of Existing and Future Electric Power Generation Options in Alberta, Canada***, Alberta Department of Energy and a consortium of energy sector stakeholders representing all of major fossil fuels and wind energy, undated (ca. 1997).

Other Impacts

New gas-fired plants: - Other impacts of new gas-fired plants will be associated mainly with development of additional industrial land. The facilities will generally be located near gas pipelines and as close to load centres as possible. Industrial cogeneration facilities are often located on land that is already alienated by the steam host. For example, two recent industrial cogeneration facilities in B.C. will generate 240 MW of electricity (with cogenerated steam) on sites that are approximately 150 m. x 150 m. (2.25 ha.). Municipal cogeneration plants would need to be located in or near other community services, so stringent emission control requirements will probably be specified.

There will be some residual community impacts such as increased noise levels, but these impacts are not considered to be significant for the purposes of this assessment because of the location on predominantly industrial land. Gas turbine facilities may emit higher noise levels than conventional steam equipment, but silencing technology is developing that can mitigate such effects. In any case, these issues will be addressed in the course of environmental assessment processes, whether provincial or harmonized under the ***Canadian Environmental Assessment Act***. Community energy projects will require special attention to residual impacts, but these cannot be determined at this stage.

New biomass-fired plants: - Biomass-fired plants will generally have smaller output than natural gas-fired facilities, but they will require relatively larger facility footprints because of the fuel storage requirements. This is true whether the fuel is woodwaste, municipal waste or other refuse derived fuel. The potentially wide range of facility designs makes it impossible to estimate the amount of land required at this stage. Woodwaste-fired facilities will generally be located near the waste generators, i.e., forest producing manufacturing facilities. They will tend, therefore, to be in areas of less than urban population densities and on industrially-zoned land.

Potential community impacts of biomass plants include additional transportation requirements for waste materials. Much of the waste material (woodwaste and municipal) is already moved some distance by truck, so the community issue is incremental truck traffic. One facility in B.C. estimated about 50 truck trips/GWh of woodwaste generation (average trip length, 130-km round trip). Not all of these would be new trips because of existing requirements to truck woodwaste for disposal in approved incineration or storage facilities.

Hydro

There are no "typical" hydro projects from which one can estimate general impact coefficients. The projects and their effects will vary markedly depending on size, location and type of facility. In Appendix B, available impact information for a number of different projects is presented. The nature and range of impacts they suggest are summarized below.

Flooding

- Limited or none in small hydro projects and for capacity additions to existing facilities
- Significant for larger new facilities
  - 4,400 ha. for Peace Site C (4.9 ha. per MW)
  - 19,000 ha. for Rapids/Wintego (57.6 ha. per MW)
  - 6,200 ha. for Tier 1 and Tier 2 Manitoba Hydro projects (with individual projects ranging from 0 – 7.3 ha. per MW)
  - 350,000 ha. for planned projects in Quebec (38.9 ha. per MW)

Other Land Requirements

- Associated transmission ranging from less than one km for small projects near the grid to some 800 km for large northern projects
  - 76 km along existing right-of-way for Peace Site C
  - 320 km for Rapids/Wintego
  - up to 800 km for Manitoba Hydro projects.
- New road rights-of-way required for some projects.

Water Flow and Water Quality

- Downstream impacts on water levels and in some cases water temperature
- Loss of spawning grounds affecting some species of fish and related activity
- In some cases composition of fisheries will change
- Impacts on food supply and habitat affecting wildlife resources and related activity
- Impacts on shoreline plants, marshes and other vegetation.

Community Impacts

- For some larger projects there is some displacement of families; short term impacts on infrastructure and services during construction; and impacts on commercial and traditional fishing, trapping and hunting activities
- In virtually all cases, agreements will be required before project proceeds to determine appropriate and acceptable mitigation strategies and to provide benefit to affected communities.

The flooding and other land requirements generally give rise to the most significant resource and resource use effects. Fisheries, wildlife, wildfowl, forestry, agriculture, archaeological and recreation and tourism resources can be affected. Some resources are diminished and lost, but in many instances it is the composition that is affected, with some resources and opportunities enhanced while others decline.

The net economic values of the resource impacts are often small relative to the total cost of the project. Indeed, in some instances, economic values are increased (e.g., with the logging of merchantable timber, enhanced access to new recreation and tourism opportunities). The community and traditional resource effects, however, can be very significant to those affected, requiring well-considered mitigation and compensation strategies prior to project development.

Wind

The environmental impacts associated with wind turbines are relatively minor, at least on the scale of operations that exist to date.

Wind farms do require a significant area of land for their operations. The exact amount will vary, but in Alberta, for example, it has been estimated that wind farms require 8 ha per MW.[8] Only a small percentage of that land (1% to 5%, or 0.08 to 0.4 ha) is occupied by wind turbines and ancillary equipment, with the remainder available for its original use. Nevertheless, in some areas and for some uses or considerations (e.g., recreation, aesthetics), the entire area is affected.

Other impacts associated with wind, particularly with older facilities, include bird deaths and noise. Bird impacts can be mitigated by site selection and tower design. Noise impacts are being reduced with new design.

Transmission Line Developments

Transmission lines will be built to connect new projects to the grid and to support increased trade.

Right-of-way widths vary by type of line. Some smaller project connections require a right-of-way 30-m wide. Major interconnections with 500 kV lines require right-of-way widths of some 75 m.

The creation of a new right-of-way can affect travel patterns of wildlife. Increased access can also affect hunting and other recreation activity.

Health concerns have been raised about the impacts of electric and magnetic fields. The use of herbicides for right-of-way maintenance is also a concern.

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[8] *Nor'Wester Energy Systems Ltd., March 1994. Economic Characteristics of Large Scale Wind Energy Development in Alberta, CANMET Energy Technology Centre.*

Impacts of Generation Changes under Different Scenarios

The Electricity Table examined the change in generation mix required to meet GHG emission constraints of 94% and 80% of the 1990 level under emission pricing. To illustrate the sensitivity of the changes to different assumptions, it examined a variety of cases for demand, gas prices, availability of existing nuclear and hydro, and the cost of CO_2 capture and storage. This study examines the overall environmental and health impacts under these different cases. The assumptions behind the various cases are described in some detail in Annex B.

Key assumptions in the base case are:

- demand grows as forecast in Natural Resources Canada's Energy Outlook;
- Alberta gas prices grow to $2.25/GJ by 2020;
- No new nuclear is allowed, but all Ontario units are refurbished as planned;
- Unlimited CO_2 sequestration is possible at $38/tonne, with some limited enhanced oil recovery sequestration opportunity at $13/tonne.

A "composite" alternative scenario assumes higher rates of demand growth and much higher gas prices. It also permits new nuclear as early as 2010. A "No Bruce A" scenario assumes these generating units (close to 3 GW of generating capacity) are not returned to service. Finally, two alternative carbon capture and storage cases assume greater low cost sequestering opportunities than assumed in the base case.

Air Emissions

The electricity output changes estimated for the year 2010 give rise to associated changes in air emissions, which are shown by province in Table C 7. In all of the cases there are reductions in coal and oil-fired output and increases in gas combined cycle and biomass output.

The net effect is a significant reduction in air emissions for all provinces with coal or oil-fired capacity, and for Canada as a whole, as shown in Table C-7 below. For example, measures to achieve a 6% reduction of greenhouse gases under the base case result in a reduction across Canada in NO_x emissions by 72,000 tonnes, SO_2 by 189,000 tonnes, primary particulate (PM_{10}) emissions by 8,000 tonnes and secondary particulate formation by 9,000 tonnes. The cases that give rise to greater reductions in coal output (e.g., the composite and no Bruce A) result in greater overall reductions of emissions. Those that have less reduction in coal output (e.g., with greater sequestering

Table C- 7

Changes in Direct Emissions compared to unconstrained base case emissions (thousand tonnes)

Scenario	BC	AL	SA	MB	ON	QC	NFL	NB	NS	PEI	CANADA
Base (6%)											
NOx	11.6	-59.4	-2.2	0.0	-10.6	0.0	-0.1	-8.7	-4.5	0.0	-72
SO_2	0.5	-107.9	-5.4	0.0	-16.4	0.0	-0.5	-33.0	-26.1	0.0	-189
PM10 (primary)	2.2	-6.3	-2.7	0.0	-1.1	0.0	0.0	-0.4	-0.3	0.0	-8
PM2.5 (secondary)	0.1	-2.4	0.0	0.0	-2.0	0.0	0.0	-1.8	-2.4	0.0	-9
Base (20%)											
NOx	11.6	-71.2	-5.9	0.0	-36.3	0.0	-0.2	-9.9	-12.6	-0.2	-123
SO_2	0.5	-128.6	-14.2	0.0	-58.4	0.0	-1.0	-39.1	-73.1	-1.2	-315
PM10 (primary)	2.2	-7.5	-7.2	0.0	-4.0	0.0	-0.1	-0.4	-1.0	0.0	-18
PM2.5 (secondary)	0.1	-2.9	0.0	0.0	-7.2	0.0	0.0	-2.1	-6.7	0.0	-19
Composite (6%)											
NOx	11.7	-69.8	-30.4	0.0	-47.3	-2.4	-1.5	-10.3	-24.1	-0.2	-179
SO_2	0.5	-115.3	-77.0	0.0	-76.8	0.0	-7.6	-36.8	-139.9	-1.2	-454
PM10 (primary)	2.3	-6.9	-39.3	0.0	-5.4	-0.1	-0.6	-0.5	-1.8	0.0	-52
PM2.5 (secondary)	0.1	-2.6	-0.3	0.0	-9.4	0.0	0.0	-2.0	-12.9	0.0	-27
Composite (20%)											
NOx	11.1	-62.3	-11.4	0.0	-54.7	-2.8	-1.5	-10.9	-25.3	-0.2	-165
SO_2	0.5	-123.2	-28.9	0.0	-88.6	0.0	-7.7	-36.9	-147.6	-1.2	-433
PM10 (primary)	2.1	-5.2	-14.7	0.0	-6.2	-0.1	-0.6	-0.5	-1.9	0.0	-27
PM2.5 (secondary)	0.1	-2.7	-0.1	0.0	-10.9	0.0	0.0	-2.0	-13.6	0.0	-29
No Bruce A (6%)											
NOx	11.6	-69.8	-4.5	0.0	-8.5	0.0	-0.2	-9.9	-5.2	-0.2	-84
SO_2	0.5	-128.7	-10.7	0.0	-13.3	0.0	-1.0	-39.1	-30.1	-1.2	-223
PM10 (primary)	2.2	-7.5	-5.5	0.0	-1.0	0.0	-0.1	-0.4	-0.4	0.0	-12
PM2.5 (secondary)	0.1	-2.9	0.0	0.0	-1.6	0.0	0.0	-2.1	-2.8	0.0	-9
No Bruce A (20%)											
NOx	11.6	-71.3	-18.9	0.0	-27.8	0.0	-0.2	-9.9	-25.3	-0.2	-140
SO_2	0.5	-129.6	-45.8	0.0	-44.4	0.0	-1.2	-39.1	-147.6	-1.2	-408
PM10 (primary)	2.2	-7.5	-23.5	0.0	-3.2	0.0	-0.1	-0.4	-1.9	0.0	-34
PM2.5 (secondary)	0.1	-2.9	-0.2	0.0	-5.5	0.0	0.0	-2.1	-13.6	0.0	-24
Sequestering1 (6%)											
NOx	11.6	-43.9	-1.8	0.0	-10.3	0.0	-0.1	-4.4	-4.2	0.0	-54
SO_2	0.5	-74.7	-4.3	0.0	-16.8	0.0	-0.5	-16.3	-24.3	0.0	-136
PM10 (primary)	2.2	-4.4	-2.2	0.0	-1.2	0.0	0.0	-0.2	-0.3	0.0	-6
PM2.5 (secondary)	0.1	-1.7	0.0	0.0	-2.1	0.0	0.0	-0.9	-2.2	0.0	-7
Sequestering1 (20%)											
NOx	11.6	-70.3	-2.2	0.0	-18.6	0.0	-0.2	-9.8	-4.5	-0.2	-94
SO_2	0.5	-125.0	-5.4	0.0	-29.5	0.0	-1.0	-39.1	-26.1	-1.2	-227
PM10 (primary)	2.2	-7.4	-2.7	0.0	-2.0	0.0	-0.1	-0.4	-0.3	0.0	-11
PM2.5 (secondary)	0.1	-2.8	0.0	0.0	-3.6	0.0	0.0	-2.1	-2.4	0.0	-11
Sequestering2 (6%)											
NOx	11.6	-27.5	-1.5	0.0	-10.3	0.0	0.1	-0.5	-4.2	0.0	-36
SO_2	0.5	-42.3	-3.6	0.0	-16.8	0.0	0.5	0.0	-24.3	0.0	-86
PM10 (primary)	2.2	-2.6	-1.8	0.0	-1.2	0.0	0.0	0.0	-0.3	0.0	-4
PM2.5 (secondary)	0.1	-1.0	0.0	0.0	-2.1	0.0	0.0	0.0	-2.2	0.0	-5
Sequestering2 (20%)											
NOx	11.6	-21.1	-1.5	0.0	-10.3	0.0	0.1	-0.5	-4.2	0.0	-30
SO_2	0.5	-30.3	-3.6	0.0	-16.8	0.0	0.5	0.0	-24.3	0.0	-74
PM10 (primary)	2.2	-1.9	-1.8	0.0	-1.2	0.0	0.0	0.0	-0.3	0.0	-3
PM2.5 (secondary)	0.1	-0.7	0.0	0.0	-2.1	0.0	0.0	0.0	-2.2	0.0	-5

opportunities) give rise to fewer reductions in emissions.[9] Small changes (less than 100 t/y) appear in the table as zeroes.

As shown in Table C-7, the NO_x and SO_2 emission reductions are quite important in Alberta, Saskatchewan, Ontario, New Brunswick and Nova Scotia. PM emission reductions are important in Alberta and Saskatchewan. Only in British Columbia do emissions significantly increase.

It must be noted that any fuel quality adjustments that might occur in the context of changing market conditions, and that might alter the effective emission factors, has not been accounted for, such as the relative price of low-sulphur (western) coal and high-sulphur (eastern) coal. Such adjustments might be conceivable at the significantly lower operating levels of coal-fired facilities in the different cases.

No adjustments to emission rates have been made for the CO_2 storage cases. Physically removing CO_2 from stack emissions will cost some energy efficiency, perhaps as much as 5-10% of plant output. This would have the effect of increasing the relative emission rate for other pollutants by roughly the same percentage. On the other hand, installation of CO_2 removal technology may expedite installation of advanced removal technology for the other pollutants. These effects would be highly variable across technologies and have not been taken into account here.

To put the primary emission reductions in perspective, they are reported in Table 5 as a percentage of the 1995 emissions inventory for each province and Canada. The base, composite, and No Bruce A cases lead to major relative reductions in provincial emissions of SO_2 especially. For example, the composite scenarios lead to 84% and 88% reductions respectively in the Nova Scotia inventory for SO_2. Other relative reductions are less striking but nonetheless appreciable.

The impacts reported in Tables C-7 and C-8 relate to direct exhaust (stack) emissions only. In Table C-9, the upstream impacts of NO_x and SO_2 are shown along with the Canadian total direct emission impacts to indicate full fuel cycle effects (for the 6% reduction base case). As shown in the Table C-9, the estimated upstream emissions of NO_x and SO_2 comprise 18% and 11% respectively, of estimated direct reductions. The upstream emissions reduce the overall reductions by these amounts. Thus, accounting for upstream emissions alters the relative impacts of fuel switching, but this does not materially change the interpretation based only on direct plant emission estimates as shown in Tables C-7 and C-8.

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[9] *It is possible that in the sequestering scenarios, measures to reduce other emissions would be put in place at the same time as the CO_2 sequestering. Under such circumstances the reductions would be greater than shown in Table 4.*

Table C- 8

Changes in Direct, Primary Emissions as Percentage of 1995 Provincial Inventories

Scenario	BC	AL	SA	MB	ON	QC	NFL	NB	NS	PEI
Base (6%)										
NOx	4.4%	-9.1%	-1.0%	0.0%	-1.9%	0.0%	-0.2%	-13.8%	-6.2%	0.0%
SO_2	0.3%	-17.7%	-4.1%	0.0%	-2.6%	0.0%	-0.7%	-28.6%	-15.6%	0.0%
PM10	0.7%	-0.4%	-0.4%	0.0%	-0.1%	0.0%	0.0%	-0.3%	-0.3%	0.0%
Base (20%)										
NOx	4.4%	-10.9%	-2.7%	0.0%	-6.5%	0.0%	-0.4%	-15.8%	-17.3%	-2.9%
SO_2	0.3%	-21.2%	-10.8%	0.0%	-9.2%	0.0%	-1.5%	-33.8%	-43.7%	-46.6%
PM10	0.7%	-0.5%	-1.0%	0.0%	-0.4%	0.0%	-0.1%	-0.3%	-0.8%	-0.2%
Composite (6%)										
NOx	4.4%	-10.7%	-14.2%	0.0%	-8.5%	-0.6%	-3.5%	-16.5%	-33.0%	-2.9%
SO_2	0.3%	-19.0%	-58.7%	0.0%	-12.1%	0.0%	-11.6%	-31.8%	-83.7%	-46.6%
PM10	0.8%	-0.4%	-5.4%	0.0%	-0.5%	0.0%	-0.6%	-0.4%	-1.6%	-0.2%
Composite (20%)										
NOx	4.2%	-9.5%	-5.3%	0.0%	-9.8%	-0.7%	-3.5%	-17.3%	-34.6%	-2.9%
SO_2	0.3%	-20.3%	-22.0%	0.0%	-14.0%	0.0%	-11.8%	-31.9%	-88.3%	-46.6%
PM10	0.7%	-0.3%	-2.0%	0.0%	-0.6%	0.0%	-0.6%	-0.4%	-1.7%	-0.2%
No Bruce A (6%)										
NOx	4.4%	-10.7%	-2.1%	0.0%	-1.5%	0.0%	-0.4%	-15.8%	-7.1%	-2.9%
SO_2	0.3%	-21.2%	-8.2%	0.0%	-2.1%	0.0%	-1.5%	-33.8%	-18.0%	-46.6%
PM10	0.7%	-0.5%	-0.7%	0.0%	-0.1%	0.0%	-0.1%	-0.3%	-0.3%	-0.2%
No Bruce A (20%)										
NOx	4.4%	-10.9%	-8.8%	0.0%	-5.0%	0.0%	-0.5%	-15.9%	-34.6%	-2.9%
SO_2	0.3%	-21.3%	-35.0%	0.0%	-7.0%	0.0%	-1.8%	-33.8%	-88.3%	-46.6%
PM10	0.7%	-0.5%	-3.2%	0.0%	-0.3%	0.0%	-0.1%	-0.3%	-1.7%	-0.2%
Sequestering1 (6%)										
NOx	4.4%	-6.7%	-0.8%	0.0%	-1.9%	0.0%	-0.2%	-7.1%	-5.8%	0.0%
SO_2	0.3%	-12.3%	-3.3%	0.0%	-2.7%	0.0%	-0.7%	-14.1%	-14.5%	0.0%
PM10	0.7%	-0.3%	-0.3%	0.0%	-0.1%	0.0%	0.0%	-0.2%	-0.3%	0.0%
Sequestering1 (20%)										
NOx	4.4%	-10.8%	-1.0%	0.0%	-3.4%	0.0%	-0.4%	-15.7%	-6.2%	-2.9%
SO_2	0.3%	-20.6%	-4.1%	0.0%	-4.7%	0.0%	-1.5%	-33.8%	-15.6%	-46.6%
PM10	0.7%	-0.5%	-0.4%	0.0%	-0.2%	0.0%	-0.1%	-0.3%	-0.3%	-0.2%
Sequestering2 (6%)										
NOx	4.4%	-4.2%	-0.7%	0.0%	-1.9%	0.0%	0.2%	-0.7%	-5.8%	0.0%
SO_2	0.3%	-7.0%	-2.8%	0.0%	-2.7%	0.0%	0.8%	0.0%	-14.5%	0.0%
PM10	0.7%	-0.2%	-0.3%	0.0%	-0.1%	0.0%	0.0%	0.0%	-0.3%	0.0%
Sequestering2 (20%)										
NOx	4.4%	-3.2%	-0.7%	0.0%	-1.9%	0.0%	0.2%	-0.7%	-5.8%	0.0%
SO_2	0.3%	-5.0%	-2.8%	0.0%	-2.7%	0.0%	0.8%	0.0%	-14.5%	0.0%
PM10	0.7%	-0.1%	-0.3%	0.0%	-0.1%	0.0%	0.0%	0.0%	-0.3%	0.0%

Table C- 9

Full Fuel Cycle Change in Emissions for Canada
(1000 tonnes/year) / Year 2010

Scenario	Stack (direct)	Upstream	Total
Base (6%)			
NO_x	-72.437	13.183	-59.254
SO_2	-188.644	20.988	-167.565

All cases produce appreciable reductions in common air contaminant (CAC) emissions in those provinces that have coal-fired production. Manitoba and Quebec, where hydroelectricity dominates, show negligible changes in CAC emissions. British Columbia is the only province that shows material increases in CAC emissions through all cases.

The results suggest that British Columbia's NO_X emissions would increase by about 5% in all cases (accounting for both stack and upstream emissions). Although these emissions would likely occur outside of the critical Lower Fraser Valley region, such an increase may still be important. British Columbia's SO_2 inventory would increase by just over 3%, mostly from upstream natural gas emissions.

The most appreciable impacts for the provinces of Alberta, Saskatchewan, Ontario, New Brunswick and Nova Scotia are the estimated reductions in NO_X and SO_2. PM emissions are reduced, but by amounts that are small percentages of the provincial inventories. Table C-8 shows that the Base (94%) case produces the most appreciable reduction in NO_X in New Brunswick and the most appreciable reductions in SO_2 in Alberta, New Brunswick and Nova Scotia. The Base (80%) case produces the most appreciable NO_X reductions in Alberta, New Brunswick and Nova Scotia and the most appreciable SO_2 reductions in Alberta, Saskatchewan, New Brunswick and Nova Scotia, as well as a sizeable reduction in SO_2 in Ontario.

The pattern is similar for the Composite (94% and 80%) cases. These cases produce major reductions in NO_X and SO_2, especially for SO_2 in Nova Scotia, where more than 80% of provincial SO_2 emissions would be removed. Similar comments apply to the remaining cases, based on Table C-8.

It should be noted that most of the upstream emissions of NO_X and SO_2 would be concentrated in the provinces of Alberta, British Columbia and Nova Scotia (in order of decreasing impacts) as the major natural gas producing provinces. Transmission and distribution compressor station emissions would occur along the length of pipelines delivering the gas to the end use facilities, but most of the upstream emissions would be associated with production and processing. NO_X emissions in the natural gas industry are allocated about 79% to production and processing and 21% to transmission and distribution.[10] This split would allocate 10,400 tonnes/year of NO_X to the producing provinces, or about 8,450 t/y to Alberta and 1,950 t/y to British Columbia, if the emissions were apportioned according to NO_X emissions from the "Upstream Oil & Gas Industry" segment of the 1995 National Emission Inventory. These values correspond to increases in provincial NO_X inventories of about 1% for Alberta and 0.7% for British Columbia. Lesser increases would accrue to several other provinces.

Similarly, apportioning the upstream SO_2 emissions according to the "Upstream Oil & Gas Industry" segment of the 1995 National Emission Inventory, about 71% of the upstream SO_2

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[10] 1990 Air Emissions Inventory for the Canadian Natural Gas Industry, *Canadian Gas Association, Standing Committee on Environment, October 1994.*

emissions would occur in Alberta and 26% in British Columbia. This would add about 15,000 tonnes/year to the Alberta SO_2 emission inventory (an increase of 2% based on the 1995 data). On the same basis, British Columbia's SO_2 emission inventory would increase by 5,500 tonnes/year (3%). Lesser increases would accrue to several other provinces.

It must be recognized that in this simplified analysis, a number of factors have been left out. One of these is upstream fugitive emissions from the various fuel sources. Only upstream gaseous emissions have been addressed here. Fugitive particulate emissions associated with coal production and use are generally subject to control measures, but may be appreciable under some circumstances. Such emissions would generally comprise particles larger than PM_{10}; therefore, they are of less concern respecting health impacts. Similarly, particulate emissions from gas production and processing flaring have been ignored. The latter will be changed appreciably, for example, by initiatives such as that announced recently by Alberta to do away with flaring altogether sometime in the future. It is not believed that either of these factors would materially affect the analysis.

As noted earlier in the report, the importance of the air emission impacts varies greatly depending on their location. Urban population impacts in total are greater in number than those in rural or less densely populated regions. Urban impacts in critical air sheds (Vancouver, Southern Ontario, south Atlantic Provinces) might be considered to be more important than those in other urban regions.

In Table C-10, the emission impacts in urban areas only are shown for the 94% of 1990 base case. Urban impacts were defined by assigning the individual plants identified in the detailed MARKAL outputs for each case into "urban" and "non-urban" groups. Facilities that are located near large urban centres, especially upwind of the centre, were identified. The emissions reductions for changes in the operating level of the plants so identified form the basis for Table C-10. Since new facilities that are expected to displace existing facilities will for the most part be relatively much cleaner, new replacement facilities were not accounted for in this approximate classification. As shown in Table C-10, the principal urban area emission reductions occur in Alberta (Edmonton), and southern Ontario. Of these, only southern Ontario is currently in an area considered to be critical from the point of view of smog management. Thus, the southern Ontario emission reductions are likely to be the most significant in terms of reduced health impacts. The general emission increases indicated for British Columbia are not expected to be in urban areas, since MARKAL shows no change in activity of the gas-fired plant in Vancouver. Additional facilities in BC due to GHG reduction targets would likely be outside of the critical Lower Fraser Valley airshed.

The appreciable NO_x and SO_2 reductions in less populated and rural areas of Alberta, Saskatchewan, Ontario, New Brunswick and Nova Scotia are all likely to be important in terms of LRTAP and potential acid raid impacts. This is particularly true of the reductions in Ontario, New Brunswick and Nova Scotia.

Table C- 10

Scenario: Urban Thermal Impact for Base-6% Reduction Relative to No Restrictions / Year: 2010

Emissions (1000 tonnes)	BC	AL	SA	MB	ON	QC	NFL	NB	NS	PEI	CANADA
NOx											
Coal (conventional)		-10.3			-7.3						-17.6
Gas (SSC)											0.0
Gas (SCGT)											0.0
Cogeneration											0.0
Gas (CCGT) -SCR or Low NOx											0.0
Total Gas											0.0
Oil								-0.9			-0.9
Biomass											0.0
Total	0.0	-10.3	0.0	0.0	-7.3	0.0	0.0	-0.9	0.0	0.0	-18.5
SO2											
Coal (conventional)		-18.2			-11.6						-29.8
Gas (SSC)											0.0
Gas (SCGT)											0.0
Cogeneration											0.0
Gas (CCGT) -SCR or Low NOx											0.0
Total Gas			0.0								0.0
Oil								-4.3			-4.3
Biomass											0.0
Total	0.0	-18.2	0.0	0.0	-11.6	0.0	0.0	-4.3	0.0	0.0	-34.1
Primary PM (PM10)											
Coal (conventional)		-1.1			-0.8						-1.9
Gas (SSC)											0.0
Gas (SCGT)											0.0
Cogeneration											0.0
Gas (CCGT) -SCR or Low NOx											0.0
Total Gas											0.0
Oil								0.0			0.0
Biomass											0.0
Total	0.0	-1.1	0.0	0.0	-0.8	0.0	0.0	0.0	0.0	0.0	-2.0
Secondary PM (PM2.5)											
Coal (conventional)		-0.4			-1.4						-1.8
Gas (SSC)											0.0
Gas (SCGT)											0.0
Cogeneration											0.0
Gas (CCGT) -SCR or Low NOx											0.0
Total Gas											0.0
Oil								-0.2			-0.2
Biomass											0.0
Total	0.0	-0.4	0.0	0.0	-1.4	0.0	0.0	-0.2	0.0	0.0	-2.1

Other Accounts

The most important other impacts will arise because of new project developments, in particular hydro and transmission. There will also be some other impacts associated with new combined cycle projects and, in some cases, wind and to a much lesser extent, new biomass projects.

In the base case, a 6% reduction in greenhouse gas emissions will give rise to a 600 MW increase in hydro capacity by 2010, relative to what would otherwise take place (i.e., without any greenhouse gas emission restrictions). Most of the increase would be in Quebec; a relatively small amount in Newfoundland. No information is available on the specific projects involved and their impacts. However, based on average requirements this could result in over 20,000 hectares of flooding.

In other cases these are hydro developments in other provinces – the Rapids/Wintego project in Saskatchewan with its 19,000 ha. of flooding; new hydro in B.C. including potentially Site C with its 4,400 ha. of flooding; and some incremental hydro development in Manitoba and Ontario, the latter with no new flooding. There could also be more hydro development in Quebec and Newfoundland than in the base case.

In most cases there are new transmission line developments, not only for specific generating projects, but also to support inter-provincial trade. In the base case there is a major addition to transmission capacity in Alberta. In other cases there are significant transmission additions in B.C., Saskatchewan, Manitoba and Ontario. In the increased CO_2 storage cases, there are reductions in transmission developments, specifically in Alberta. The right-of-way requirements and impacts of the affected projects are not specifically known.

There is no increase in wind capacity for a 6% GHG reduction in the base case, but there are for larger reductions and in other cases. Under the 6% reduction "composite" alternative case, for example, some 10,000 MW of wind capacity would be developed across the country. The land requirements would be in order of 80,000 hectares. There would be considerable new combined cycle development in all of the cases. However, as noted earlier, these developments (like any new biomass) would generally be on industrial land, with relatively minor incremental effect.

Table C- 11

National Emission Inventory of Common Air Contaminants by Province

Principal emissions by province in 1995 National Emission Inventory (t/y)

Province	NOx			SO2			PM10			PM2.5		
	PwrGen	Province	% PwrGen	PwrGen	Province	% PwrGen	PwrGen	Province	% PwrGen	PwrGen	Province	% PwrGen
BC	4172	263914	1.6%	369	176111	0.2%	454	302850	0.1%	427	175188	0.2%
AB	90734	653319	13.9%	130471	608100	21.5%	8973	1580470	0.6%	8777	268963	3.3%
SA	47509	214491	22.1%	108536	131100	82.8%	21669	733883	3.0%	7309	172598	4.2%
MB	907	109073	0.8%	1361	365475	0.4%	421	407311	0.1%	210	133016	0.2%
ON	59399	555884	10.7%	74730	632762	11.8%	1680	1044515	0.2%	719	260020	0.3%
QC	1286	383144	0.3%	283	373647	0.1%	30	646483	0.0%	24	177298	0.0%
NB	16550	62657	26.4%	67330	115542	58.3%	174	124488	0.1%	120	35167	0.3%
NS	24330	73060	33.3%	134883	167071	80.7%	458	114813	0.4%	281	34569	0.8%
NFL	3690	42658	8.7%	15704	65014	24.2%	897	102189	0.9%	656	30861	2.1%
PEI	141	7977	1.8%	294	2547	11.5%	15	24315	0.1%	12	4921	0.2%
10 PROV	248718	2366177	10.5%	533961	2637369	20.2%	34771	5081317	0.7%	18535	1292601	1.4%
CANADA*	254985	2463971	10.3%	534323	2653571	20.1%	34874	5370694	0.6%	18633	1519149	1.2%

* CANADA numbers include additional emissions from Yukon and NWT

Impact Summaries for Selected Hydro Developments[11]

Kokish River Hydro Electric (BC Hydro) (16 MW)

Flooding and Other Land Requirements

The project will not cause flooding, but 8.8 hectares of land will be required for facilities and associated transmission. The required transmission line is 0.5 km. in length and 30 m. wide. The land required for the project is currently used for recreation and is significant to First Nations. Resource impacts include:

- Vegetation
  - One red-listed species (*Geum schofieldii*) is known to occur in the project area. The effect on this species would be low. There may also be some blue-listed vegetation that could be impacted by roads if plant surveys are not conducted. The project will consume 0.519 ha of old growth and 0.195 ha of flood plains.
- Wildlife
  - Vegetation clearing will alter 5.5 ha of habitat; however impact to species such as goshawk and marbled murrelet should be negligible.

Water Flow and Water Quality

- Fish
  - Three regionally significant fish species will be moderately affected due to difficult access to upper reaches as the result of low flows. Chum and pink salmon in the lower river could be affected by increased silt from project activities and/or by short-term flow variations.
- Vegetation
  - The following blue-listed vegetation will be affected by low flows in some portions of the river: smooth douglasia, queen charlotte isopyrum, ligusticum calderi, nodding semaphore grass, queen charlotte butterweed, mountain fern and queen charlotte twinflower violet. Queen Charlotte avens could also be affected by water flow fluctuations. Increase in purple-laced willow herb as a result of increased available habitat will create a positive impact.

Community Impacts

- First Nations
  - The land and resources affected by the project have important values for which First Nations have potential or existing land claims. The Nimpkish band has indicated an interest in participating in the project.

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[11] *Study prepared for the Electricity Table of the National Climate Change Process by Marvin Shaffer &Associates Ltd. and Alchemy Consulting Inc., June 1, 1999 The Table's schedule did not permit discussion or adoption of these findings.*

Peace Site C (BC Hydro) (900MW)

Flooding and Other Impacts

Approximately 4400 hectares of land will be lost due to flooding. A transmission line from Site C to the existing Peace Canyon will be required. It will be 76 km. in length along an existing, but expanded right-of-way, affecting an additional 560 ha. of land.

Resource Impacts

- Wildlife
  - The project will impact local levels of mule deer, moose populations, and ruffed grouse and, potentially, white-tailed deer and elk. None of these species are red or blue-listed. A variety of furbearers and carnivores are present in the study area.
- Waterfowl
  - A variety of migratory waterfowl are present in the study area.
- Fish
  - The major aquatic species present are: mountain whitefish, arctic grayling, rainbow trout, lake whitefish and walleye. Longnose sucker, large scale sucker, white sucker and northern squawfish are also present. Some fish populations may increase (northern pike), some may stay the same (mountain whitefish, arctic grayling) while others may decrease due to increased angling pressure (bull trout: red-listed).

Resource Use Impacts

- Forestry
  - 950 hectares of merchantable timber will be flooded (approx. one week's worth of timber supply for an average sawmill in the region). All merchantable timber will be harvested before flooding.
- Archaeology and Heritage
  - 112 of 241 known heritage sites in the study area will be directly impacted by flooding.
- Recreation and Tourism
  - Recreational opportunities along some areas of the river and on the channel islands are expected to decline. River boating and canoeing opportunities will be lost; however, individuals may shift to standing water activities. Possible rough water and reservoir fluctuations may inhibit recreational activities. No loss is regional tourism is expected, the project may attract some tourists.
- First Nations
  - The following concerns were raised by first nations representatives: the impact of habitat loss and resulting decrease in moose population which is staple of their diet; the increase recreational hunting pressure if a road was built across the dam.

Water Flow and Water Quality

- Water temperature is expected to increase by approximately 2-3 degrees Celsius in summer. Losses in spawning habitats in the Moberly River and Lynx Creek are anticipated.

Community Impacts

- Approximately 25 families will be relocated as a result of the flooding.
- The community of Fort St. John could be impacted by an influx of workers during construction.

Waneta Expansion (BC Hydro) (380 MW)

Flooding and Other Land Impacts

- No flooding will be caused by this project. However, approximately 27 hectares of land will be required – 6 ha. for the spillway and some 21 ha. for the associated transmission.

Water Flow and Water Quality

- Sturgeon has been identified as likely to be affected. This may occur as a result of increased flows at the top of the Waneta Eddy, which provides important habitat. The increase flows could disrupt habitat formation, reduce normal flushing or cause increased sedimentation. Loss of habitat and habitat alienation is likely to affect species downstream.

Community Impacts

- Short term impacts on some communities' infrastructure and services could occur during construction.

Brilliant Expansion (BC Hydro) (150 MW)

Flooding and Other Land Impacts

There will be no flooding for this project. Approximately 3 hectares of land are required for the construction of the power plant expansion and 6 hectares for transmission.

Water Flow and Water Quality

- Two red-listed species (Umatilla Dace, White Sturgeon) and one blue-listed species (Shorthead Sculpin are found below the Brilliant Dam in the Kooteney River. The Brilliant Expansion is not expected to affect the persistence of these or other species.
- Entrainment of fish through the turbines is not expected to change significantly. It is unclear whether entrainment rates would increase or decrease.
- Benefits of this project include the reduction of total dissolved gases as a result of reduced spillways volume and frequency thus improving fish productivity.

Rapids/(Wintego) Project (SaskPower) (330MW)

Flooding and other land requirements

The project will flood approximately 19,000 ha of land. Currently the primary land and resource use in the flooded area is fishing and trapping. The project will also require a 320-km transmission line from the site to Beatty, Saskatchewan, with a right-of-way some 30-50 m. wide. About 46 km of new road will also be required

Resource Impacts

- Fish
  - Population of coarse fish, whitefish, ciscoes, plankiverous ciscoes, and lake trout will all increase as a result of flooding. This is a result of longer growing seasons, thermal layering and new spawning grounds. A decrease in population of shallow-water fish such as walleye and northern pike will occur, largely the result of a shorter growing season.
  - Construction of access roads may cause silting of fish spawning areas.
- Wildlife
  - Some species of small birds resident along shorelines may increase on account of increased shoreline. Flooding will reduce eagle populations by reducing habitat, and bald eagles will experience a loss of spring food. Resident duck populations will also be reduced due to loss of habitat. Common terns will experience temporary displacement and breeding disruption. Loss of habitat will result in a decrease in the variety of birds. Beavers will also experience a loss of habitat.
- Vegetation
  - Productive vegetation will be replaced by less productive bog and fen vegetation. Some rare species of aquatic and marsh plants may be reduced in numbers. Floating fen vegetation will develop on floating peat mats.
- Waterfowl
  - There will be a temporary loss of habitat for shore and littoral invertebrates and elimination of habitat for spring staging waterfowl.
- Archaeology
  - Approximately 90% or 250 out of 281 prehistoric sites in the region will be flooded. Five pictograph sites will also be flooded.

Resource Use Impact

- Fishing
  - Annual capacity of commercial fish will increase from 290,500 to 451,200 pounds, although yield per unit area will decrease from 3.70 to 2.70 pounds/acre/year. Commercial fishing will change from pike-walleye-whitefish to the lower priced trout-whitefish mix, although pike and walleye will remain common. New roads will reduce transportation costs for commercial fishing.
- Forestry

  - An estimated 42,000,000 cu. ft. of merchantable timber valued at 3.25 million in 1974 prices will be flooded. However, the economic impact on the forestry industry is positive because the reservoir will provide early access to commercial stands that would otherwise remain untouched for many years. In present value terms, the immediate returns more than offset the loss due to flooding.

- Recreation and Tourism
  - Due to increased and lower cost accessibility, recreation and tourism (boating, camping, commercial outfitting, cottages, sport fishing) in the area of the reservoir is likely to increase.
- Mining
  - No major known body of ore will be flooded. Mineral exploration will be easier and lower in cost due to a road and river crossing at Wintego Lake facilitating the transportation of ore from future mines east of Reindeer River to the smelter at Flin Flon.
- Hunting and Trapping
  - An increase in hunting and trapping activity is expected as a result of increased accessibility to the area, but harvests of some species will decline because of resource impacts.

Proposed Mitigation

Proposed mitigation measures will likely include excavation of significant archaeological sites and reservoir clearing. A detailed mitigation package has not been developed yet.

Water Flow and Water Quality

Resource Impacts

- Fish
  - Downstream increase in fall and winter water levels aids the reproduction of whitefish, lake trout, and cisco. Loss of spawning ground and feeding areas will affect some species of fish. An overall increase in fish foods will increase fish populations. Winter drawdowns greater than 1 ft. will increase the mortality rate of incubating fish eggs. An overall change in composition of fish population downstream will result from water level fluctuations.
- Wildlife
  - Downstream food supply for bears may be reduced. Small fluctuations in water level during the winter will benefit beaver and muskrat downstream. Loss of habitat will reduce otter populations by 25% and mink populations by 25%-40%. Two nesting colonies of common terns downstream may be affected adversely.
- Vegetation
  - There will be adverse downstream effects on littoral invertebrates, and shoreline plants due to water fluctuations. Marshes and meadows in protected shallow bays will be less extensive than under the natural water regime.

Resource Use Impacts

- Recreation and Tourism
  - Loss of whitewater for canoeing. River travel will be facilitated. Later start for water transportation.
- Hunting and Trapping
  - Potential harvest of: beaver, muskrat and mink downstream will be reduced.

Community Impacts

- No displacement of communities by this project.
- Improvements in community infrastructure through upgrading of telecommunications and roads.
- Increased social stresses during construction.

Manitoba Hydro

Tier 1 Projects (most economic; could be implemented by 2010 (860 MW)

These projects combined will result in flooding of some 4,200 hectares, currently used for hunting, trapping and fishing. Major transmission lines, including an 800-km line running east of Lake Manitoba, 76 m. wide, will be required on boreal forest and at the southern end, on agricultural land.

There will be some impacts on fish, wildlife, native cultural resources, recreational activity and agricultural operations. Mitigation will be developed in a planning process with Cree Nation and other affected parties.

Tier 2 Projects (could be implemented by 2015) (1,465 MW)

These projects combined will result in the flooding of some 2000 hectares of land, with some 250 km of transmission line development incremental to what will be required for the Tier 1 projects. The land is currently subject to limited activity and no communities will be displaced. There will be some impacts on fish, wildlife, and archaeological resources and on recreational activity. Again, mitigation measures will be developed in a planning process with Cree and other affected interests.

Hydro Quebec

Planned projects will flood 350,000 hectares to develop approximately 9,000 MW of capacity and 40 TWh of energy. Forty percent of this power will come from already existing plants, the rest from new power plants. Partnership agreements will be developed to develop mitigation strategies and provide opportunities, including possible local ownership, for sharing benefits.

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AGRA Monenco – *Assessment of Costs and Characteristics of Fossil Fuel Technologies for Electrical Generation*

Cleghorn & Associates Limited and Acres International Limited – *Assessment of Cost and Characteristics of Hydroelectric Generation*

Hagler Bailly Canada with J.P. Bayne of Bayne Advisors– *Assessment of Cost and Characteristics of Transmission, Provincial Load Forecasts*

OCL Services Group – *Assessment of Cost & Characteristics of Nuclear Technologies for Electrical Generation*

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